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Poised for **growth.**

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**IVANHOE
ENERGY**

2001 ANNUAL REPORT

OUR MISSION

To create value for shareholders by focusing on cleaner energy solutions, such as:

1. Production of cleaner burning fuels from natural gas using proven GTL technology.
2. Natural gas and oil exploration and production in the United States.
3. Natural gas and enhanced recovery developments on a production-sharing basis with national energy companies.

Gas and Oil Development in China



Gas to Liquids in the Middle East



Natural Gas Exploration in the U.S.



Poised for Growth

Since joining the company in 1998, we have pursued the goal of growing Ivanhoe into a large successful energy company by pursing strategies that provide for cleaner burning energy solutions. Our key growth strategies are focused in the United States, China and the Middle East. During 2001 we made considerable progress and as we move into 2002, Ivanhoe is poised for explosive growth as each of our key strategies matures toward definitive agreements and valuable projects. Already, interest among professionals on Wall Street is growing, as evidenced by continued support from our major shareholders and increased research coverage.

In both California and Texas we began drilling important exploration targets that are focused on cleaner burning natural gas. Our California exploration portfolio has now grown to over 25 prospects with an estimated gross reserve potential of more than eight trillion cubic feet equivalent. We began our first deep-gas test at Northwest Lost Hills targeting the highly prospective Temblor formation. In 2002, we will continue to drill there and on other natural gas prospects from our exploration portfolio.

In Texas, we have started exploring on our extensive acreage position in the East Texas Bossier gas play. After forming a 50/50 joint venture with Unocal, which combined Ivanhoe's leasehold position with Unocal's ability to manage a large drilling program, we drilled two wells at our Cresslen Ranch prospect. In 2002, we plan to further evaluate the Cresslen Ranch finds and to continue drilling additional prospects from our exploration portfolio.

Another of our key growth strategies is centered on China. For the past year or so, Ivanhoe has been conducting pilot tests on enhanced oil recovery projects in the Dagang and Daqing fields and also evaluating data for primary natural gas development in the prolific Sichuan basin. Development of the Dagang field is under review now and we expect to have definitive production-sharing contracts for our three large blocks in Sichuan province during the first half of 2002.

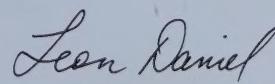
Considerable progress has been made in our discussions with national petroleum companies for gas-to-liquids projects in the Middle East. In Qatar, we are proposing to build a facility that could produce approximately 185,000 barrels a day of ultra clean transportation fuels and another 155,000 equivalent barrels a day of natural gas liquids. This would be the largest facility of its kind in the world and is expected to generate revenues in excess of \$10 million dollars per day. Additionally, we began exploring financial and marketing opportunities in Japan with a commercialization study to investigate the utilization of the products from the proposed Qatar project.

Discussions also continue for smaller GTL projects on the Mediterranean coast of Egypt and elsewhere. So we remain strongly committed to the growth opportunity in providing clean transportation fuels from natural gas. Engineering advances have dramatically reduced the capital costs of producing these ultra-clean green fuels from natural gas. Our vision, experience and determination combined with tighter environmental standards to improve air quality will put Ivanhoe Energy in the vanguard of the green fuels megatrend.

Finally, as further evidence of our corporate maturity, we were very pleased to add Howard Balloch to the Board of Directors. Mr. Balloch will contribute an enormous amount of experience and leadership as we pursue our business objectives.



David Martin
Chairman



Leon Daniel
President & CEO

As we have defined in our mission, we are striving to create value for shareholders with a global focus on natural gas-based strategies. From these strategies we have developed objectives with short, medium and long-term impacts on our business.

Our short-term objective is to focus on areas where production can be achieved quickly and efficiently to create cash flow to fund operations and allow us to pursue our medium and long-term objectives. To date, we have established production in the Spraberry Trend of West Texas, at South Midway Sunset in the San Joaquin Basin of California and at the Dagang enhanced oil recovery project in China. Our medium term objective is focused on the deep natural gas potential of the San Joaquin Basin of California, the Bossier gas sands of East Texas and the Sichuan Basin of China. Our long-term objective is to become a leader in the development of gas-to-liquids (GTL) projects. We foresee rapidly increasing future demand for clean energy as environmental regulations become more stringent and the world's supply of crude oil becomes more sour and heavy. We plan to apply Syntroleum's proprietary GTL technology in the production of environmentally-clean synthetic fuels from stranded natural gas deposits, which would otherwise be uneconomic to exploit.



Ivanhoe has advanced each of these objectives during the past year and is now poised for explosive growth as each project matures and its value becomes apparent to the financial community, our peers and the general public.

US Development Projects

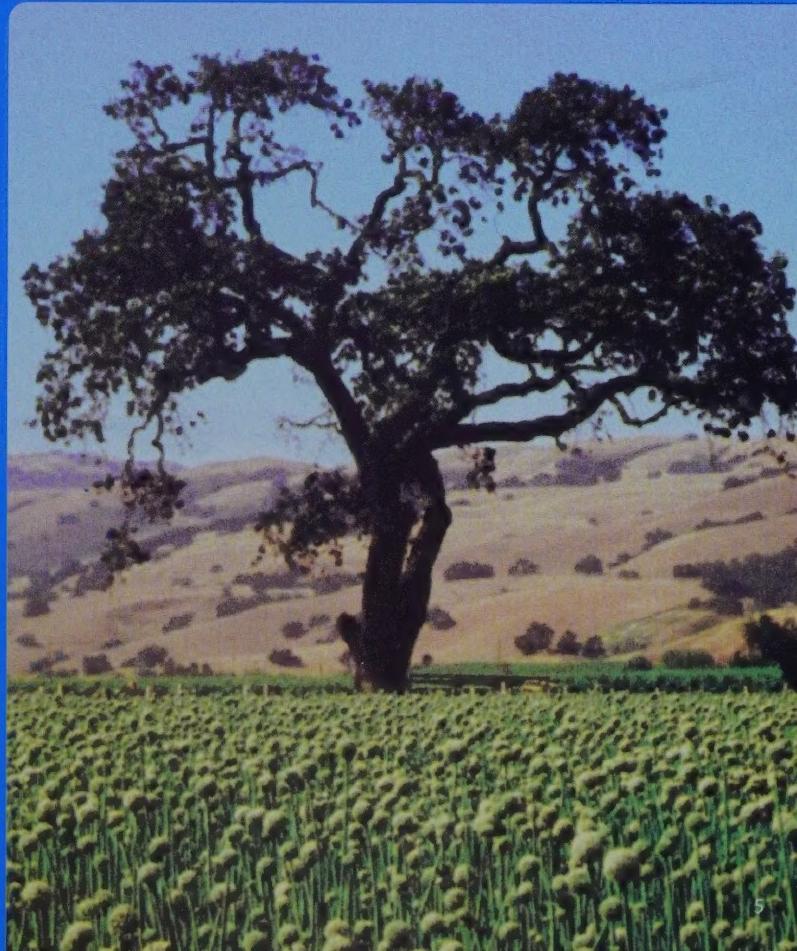
Our investment in these conventional oil and gas projects are primarily designed to provide immediate cash flow from low-risk, low-cost developments with existing infrastructure. While not all our operations are natural gas based, the cash flow generated is providing support for our emerging natural gas exploration and production activities and our gas to liquids programs.

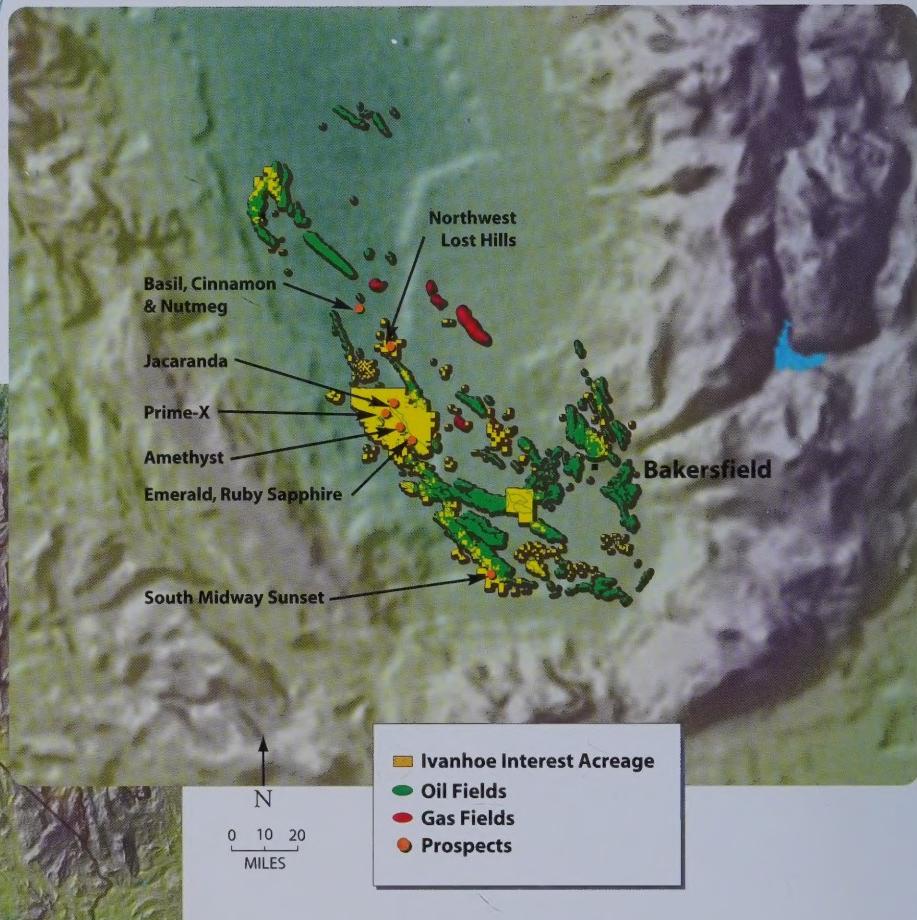
Spraberry, West Texas

In April 2000, we entered into a partnership to jointly develop over 10,000 gross acres of oil and gas exploration properties in the Spraberry Trend of the West Texas Permian Basin. As of the end of 2001, thirty wells had been drilled in the Spraberry field, which produced more than 725 barrels of oil equivalent per day in the fourth quarter. Following a pause in our development drilling to evaluate production performance and to await higher oil prices, we have recently resumed drilling in the Apache Flats area of the trend.

South Midway Sunset, California

During 2001, we continued our planned development drilling program in the South Midway Sunset Field located in Kern County, California. Ivanhoe's lease produced approximately 450 barrels of oil per day from 29 wells during the fourth quarter of 2001. In addition, we were very encouraged by a cyclic steam injection project, which more than doubled production rates in the five wells that were treated in an initial pilot program. A full-scale cyclic steam project is now being planned and should commence during the first half of 2002. As operator, we own a 100% working interest and a 93% net revenue interest in the project.





California Exploration Portfolio

A valuable and unique quality of our California exploration program arises from the opportunity to prospect for new oil and gas potential beneath existing fields in the San Joaquin Basin - one of the most prolific oil and gas producing regions in the Lower 48 states. We gained this opportunity in 1998, when we acquired rights to an exploration agreement with Aera Energy LLC, California's largest oil and gas producer, in an area of more than 250,000 acres in the San Joaquin Valley. This agreement gave us access to a significant inventory of exploration, seismic and technical data for the purpose of identifying drillable exploration prospects. We have a right to participate in all of the drillable prospects that have been presented to Aera.

Since 1998 and prior to the term of this agreement expiring in 2001, Ivanhoe has identified over 40 separate prospects and leads within 14 outlined prospect areas covering approximately 72,800 acres. We estimate that the top 25 drillable prospects out of this exploration portfolio will expose Ivanhoe to a gross reserve potential for eight trillion cubic feet equivalent of natural gas. To date, only two prospects from this portfolio have been or are being tested. The well at our Northwest Lost Hills prospect is currently drilling while the Belgian Anticline prospect was drilled unsuccessfully in 2001.

Northwest Lost Hills

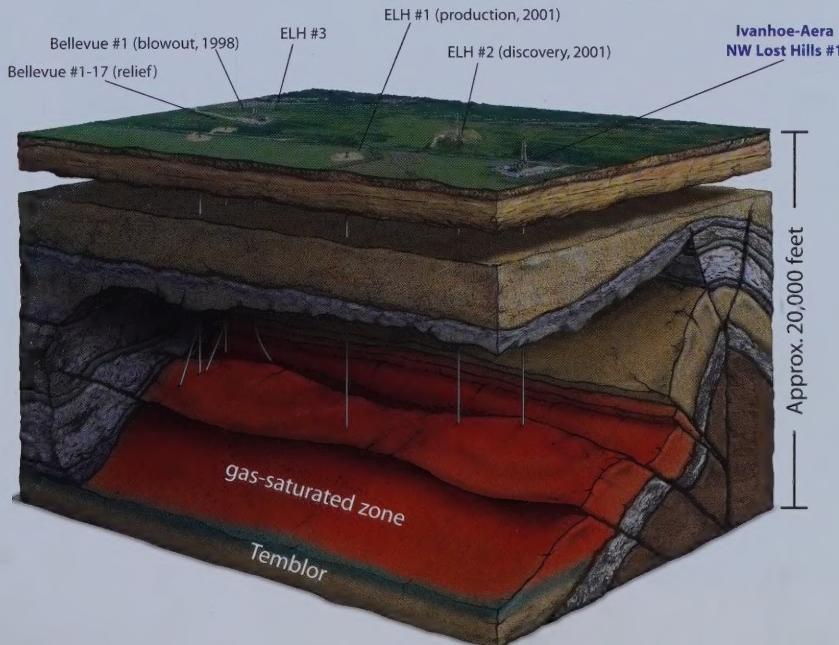
The Northwest Lost Hills 1-22 well, located in Kern County and operated by Aera, began drilling in August 2001. The well has been designed to fully evaluate the natural gas and condensate reserve potential of the deep Temblor formation and reach a depth of approximately 20,000 feet. Our well location lies on trend with, and several miles northwest of, the Bellevue No. 1 blowout well that indicated the potential for huge gas reserves in the Temblor formation.

This high profile well was initially drilled to a depth of 18,400 feet and encountered the top of the Temblor formation objective. However, prior to the setting of casing, geological information from this portion of the Temblor formation indicated that the bottom hole could be placed in a more structurally favorable location. The well was successfully sidetracked and drilled to the top of the Temblor at 17,040 feet. At that point, casing was set from the surface to the bottom of the hole in order to maintain well control while drilling into the high pressure sands expected in the objective formation. In the 9,600 gross acres encompassing the Northwest Lost Hills prospect, we hold an average working interest of 38% and a 42% working interest in the well that is currently drilling.

Ivanhoe had become interested in the deep-gas potential of the San Joaquin Basin well before the play was highlighted by the Bellevue No. 1 well, which blew out after encountering the Temblor formation in 1998. This well continued to flare natural gas and condensate for more than four months with estimated initial flow rates of more than 100 million cubic feet per day. The operator, Berkley Petroleum (acquired by Anadarko Petroleum in March 2001), has since drilled four follow-up wells to further test the Temblor, but with limited success. However, the East Lost Hills #1 well was successfully completed in February 2001 and began flowing with initial rates of 15 million cubic feet 923 barrels of condensate per day.

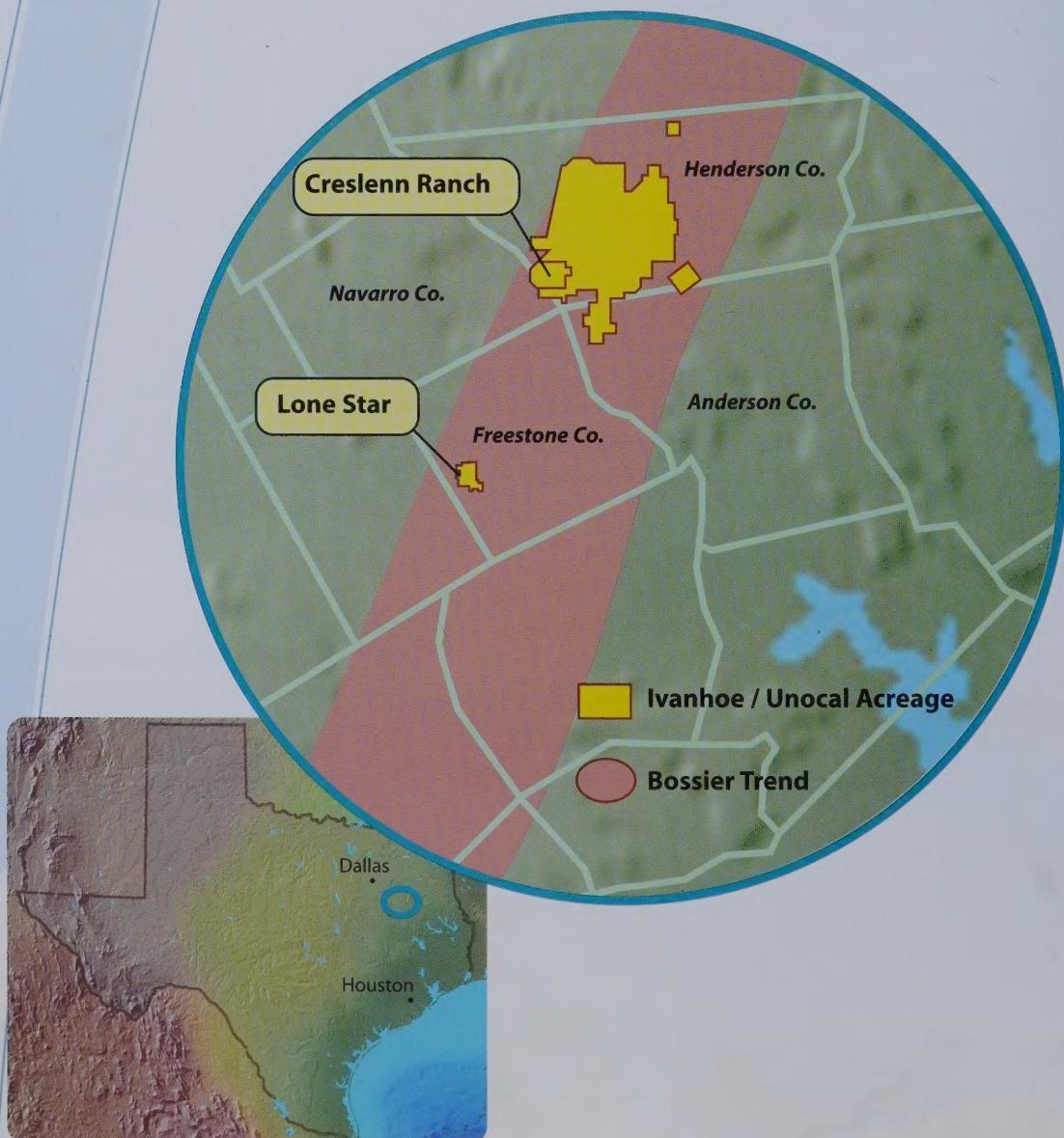


Deep Gas Drilling at Lost Hills



Bossier Gas Play - East Texas

During 2001, Ivanhoe formed a 50/50 partnership with Unocal to begin drilling exploration wells and we expanded our mineral rights in the Bossier Trend to over 58,000 gross acres. In return for our contribution of acreage and up front exploration costs, Unocal will be the operator and spend the first \$10 million toward exploration drilling. Based upon pre-drill cost estimates, Ivanhoe should be carried on the first five or more wells drilled. After investment equilibrium is reached, the companies will equally share exploration and development costs. Together we have defined several additional prospective areas over this acreage position, which are primarily located in Henderson, Anderson and Freestone counties.



The first two wells we drilled are located on the Creslenn Ranch prospect in Henderson County. Both wells encountered Bossier sand formations that indicated the potential for natural gas production. Fracturing and testing operations are underway on the 2-Trintiy Materials well. Evaluation of these results will determine the completion methods for the 1-Trinity Minerals well. While the Creslenn Ranch wells are being evaluated, the drilling rig has been moved south to Freestone County where drilling has commenced on the Lone Star prospect.

With proximity to the extensive infrastructure, our Bossier drilling program has the opportunity to provide meaningful, near-term growth in our production and revenues from natural gas. The Bossier sand is a large, contiguous interval in an area of East Texas that has shown to have a high probability of success based upon existing well control. Based upon industry activity to date, primarily in Freestone County, a typical Bossier well produces between two and four million cubic feet of natural gas per day. Additionally, each of our prospects contains valuable secondary objectives at depths above the Bossier.



GTL technology converts natural gas into liquid synthetic fuels that are free of sulfur and aromatics - greatly exceeding new and proposed U.S., Japanese and European Union environmental regulations. Recent announcements by many of the world's major energy companies, including BP, Shell, Sasol and Chevron, that they are committed to funding GTL projects worldwide are evidence of GTL's growing momentum. We remain strongly committed to the belief that providing clean transportation fuels from natural gas can provide significant growth potential for

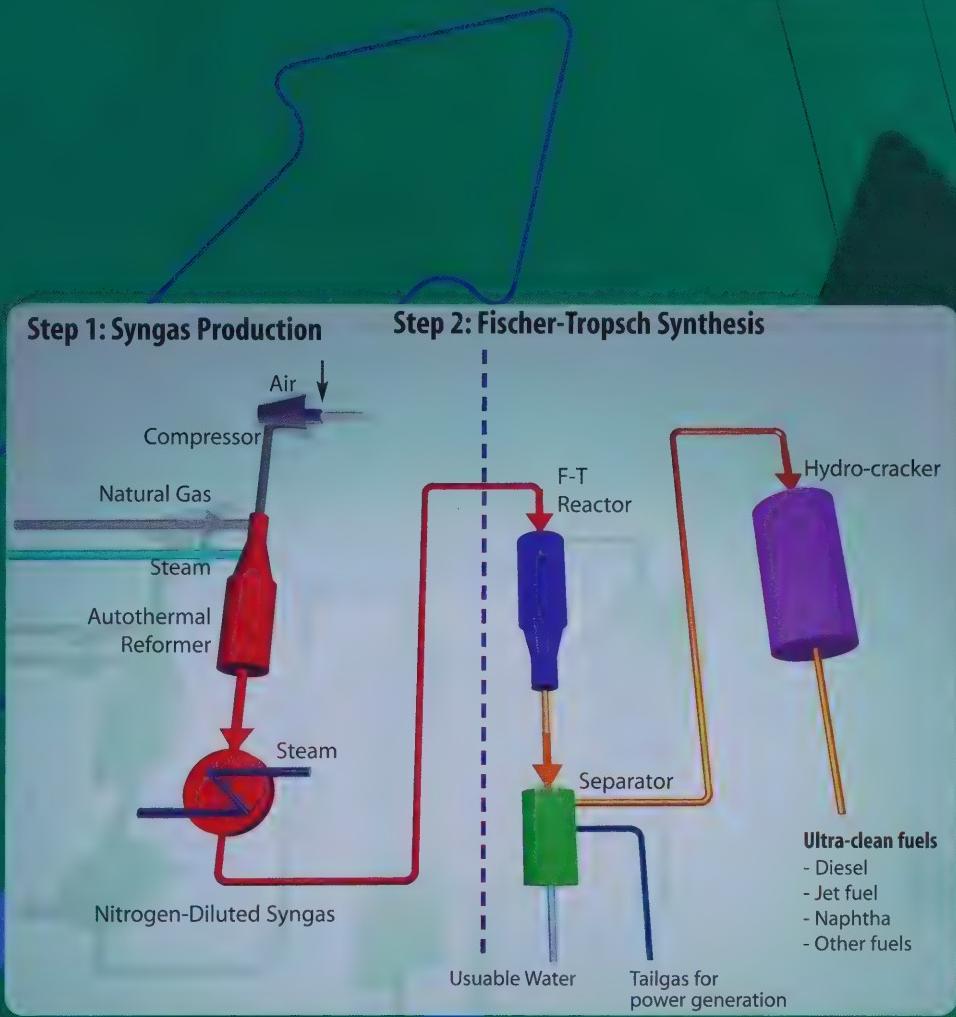
GTL Outperforms Crude Oil Diesel

Property	Current Crude Oil Diesel	2006 Diesel Requirements	GTL Diesel
Sulfur (PPM)	500	15	Zero
Aromatics (%)	~30	~30	Zero
Cetane Index	~45	~45	>74

Ivanhoe. Engineering advances have dramatically reduced the capital costs of producing these ultra-clean green fuels from natural gas. Our vision, experience and determination combined with tighter environmental standards to improve air quality will put Ivanhoe Energy in the vanguard of the green fuels megatrend.

The benefits of GTL technology are becoming very clear. GTL has the potential to convert the trillions of cubic feet of stranded gas in the world into billions of barrels of economic value. Countries that control the gas will realize great value from the investment, jobs and revenue that will result from the development of these deposits. Furthermore, the products and fuels from GTL plants can be transported and sold through conventional tanker, pipeline, storage facilities and retail distribution systems. The GTL process yields the highest quality synthetic hydrocarbons that can be used directly as a fuel, in a normal diesel engine, or blended with lower quality crude-derived diesel fuel to help it meet more stringent environmental and performance requirements.





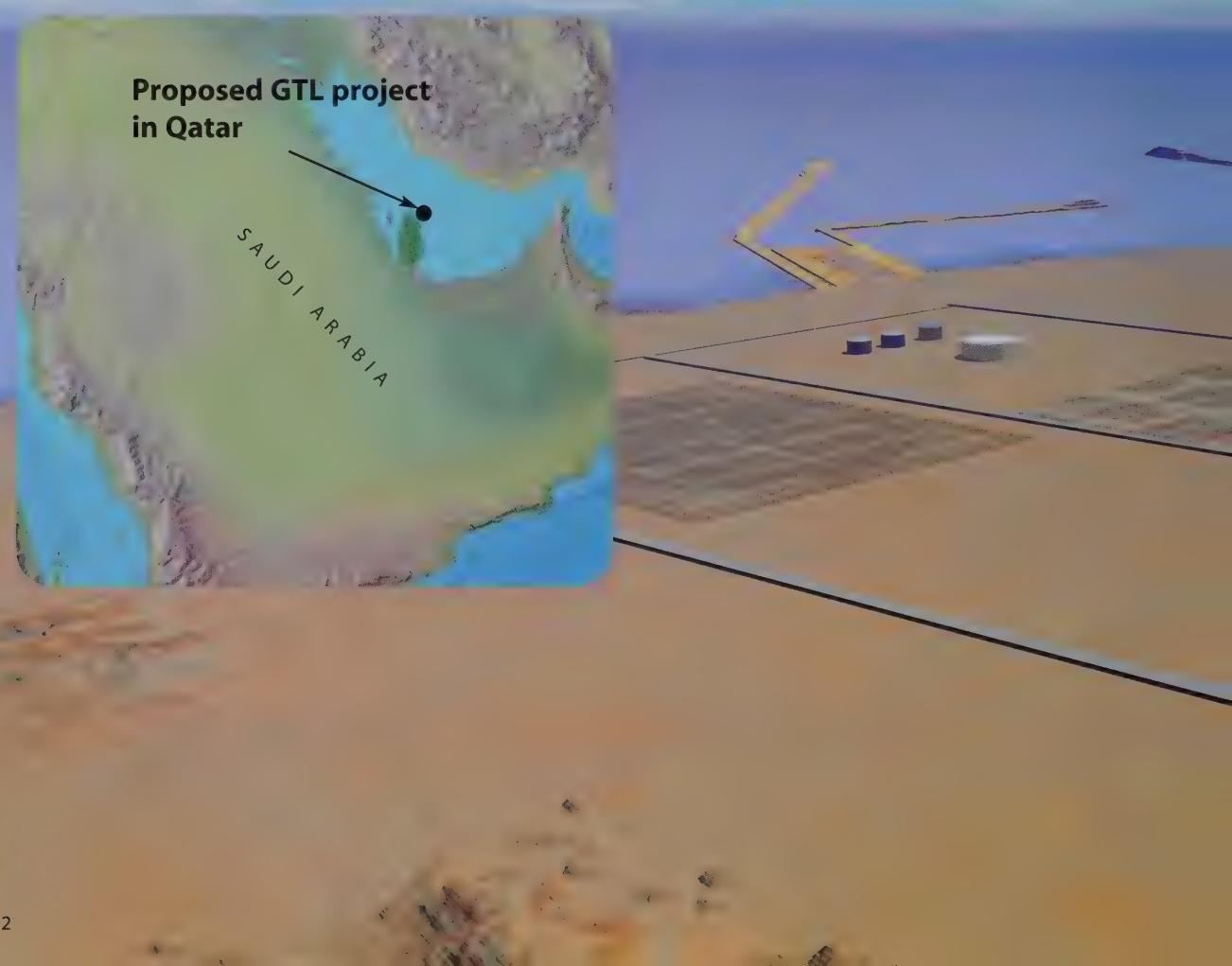
The Syntroleum Process

In 2000, we acquired a non-exclusive master license entitling us to use Syntroleum's proprietary GTL process in an unlimited number of projects in most areas of the world with unlimited production volume restrictions but excluding North America, China and India. In the patented Syntroleum process, natural gas is mixed with compressed air and steam to produce a synthetic gas. Then, through a catalytic reaction, the gas is converted to a range of ultra-clean synthetic oils that can be further refined to produce transportation fuels and hydrocarbon products. Potentially valuable by-products include heat, which can be used to produce electricity, and agricultural-grade water. The Syntroleum process is a cost-effective refinement of GTL technology that has been in use for generations. A major advantage is that the process uses compressed air instead of pure oxygen to facilitate the conversion reaction, substantially reducing the capital costs and vastly improving the safety of the process plants.

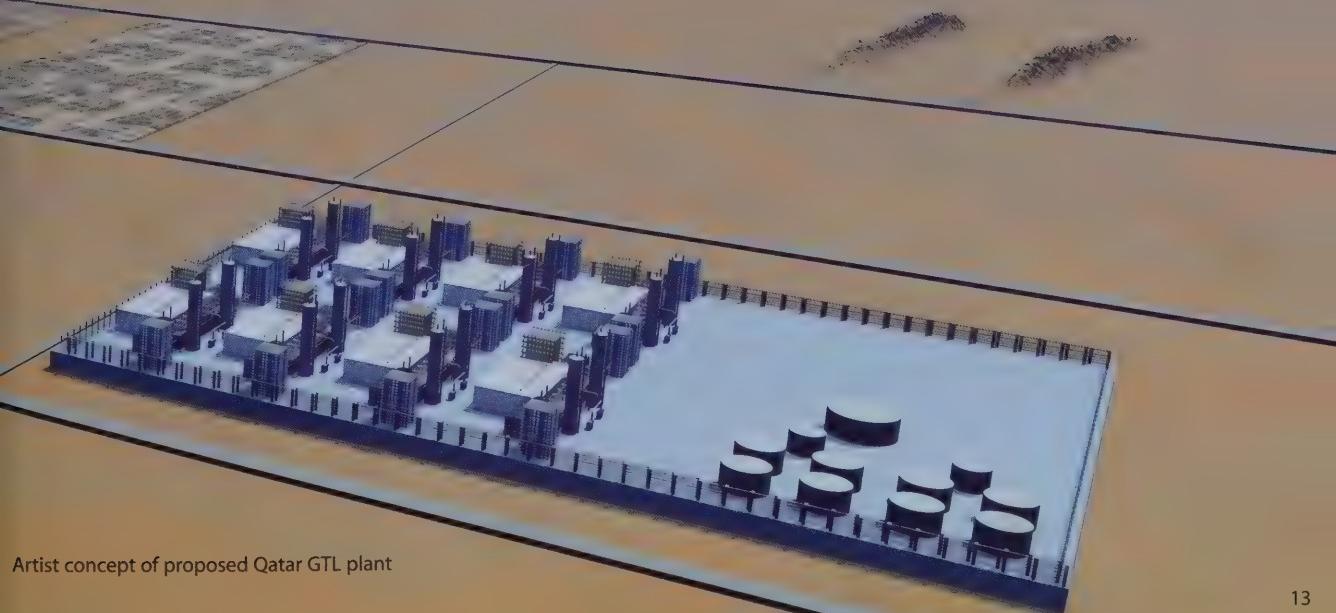
GTL Projects in Qatar and Egypt

During 2001, we undertook detailed project feasibility studies for the construction, operation and cost of world-class GTL plants in both Qatar and Egypt. The study for Qatar included the development of offshore gas, bringing that gas to shore and dehydrating it, provision for gas liquids extraction via a Natural Gas Liquids Plant, provision for a 185,000 barrel per day GTL Plant, and product storage and offloading facilities. Our primary proposal is designed to provide the maximum amount of GTL product. Additionally, from the process, we also would be able to provide supplemental power and water to the local community.

Ivanhoe has undertaken a commercialization study in Japan to investigate the optimum commercial structure for utilization of GTL and NGL products produced in Ivanhoe's planned Qatar project. The study will include identifying the role that Japanese companies can play as purchasers of the products, and competitive suppliers of equipment, materials, services and finance in the project. Ivanhoe initiated the study by signing a Memorandum of Understanding with Inpex and Mitsui. Other companies will be invited to participate in the study to obtain the broadest scope and input.



While many of the feasibility studies undertaken for Qatar have applicability to Egypt, additional studies undertaken for Egypt contemplate the gas being purchased, rather than developed, and the plant size is forecast at 90,000 Bbl/d. In addition, we conducted two marketing and transportation feasibility studies. Marketing studies were conducted for both Europe and the Asia-Pacific regions for GTL diesel and naphtha. Markets within these regions were identified and premiums for the GTL ultra-clean fuels were estimated. Product forecasts from these studies will be used as the basis for evaluating the commerciality of each of the GTL projects. The results of these studies are to be utilized during the course of commercial discussions, which should continue during the first half of 2002.



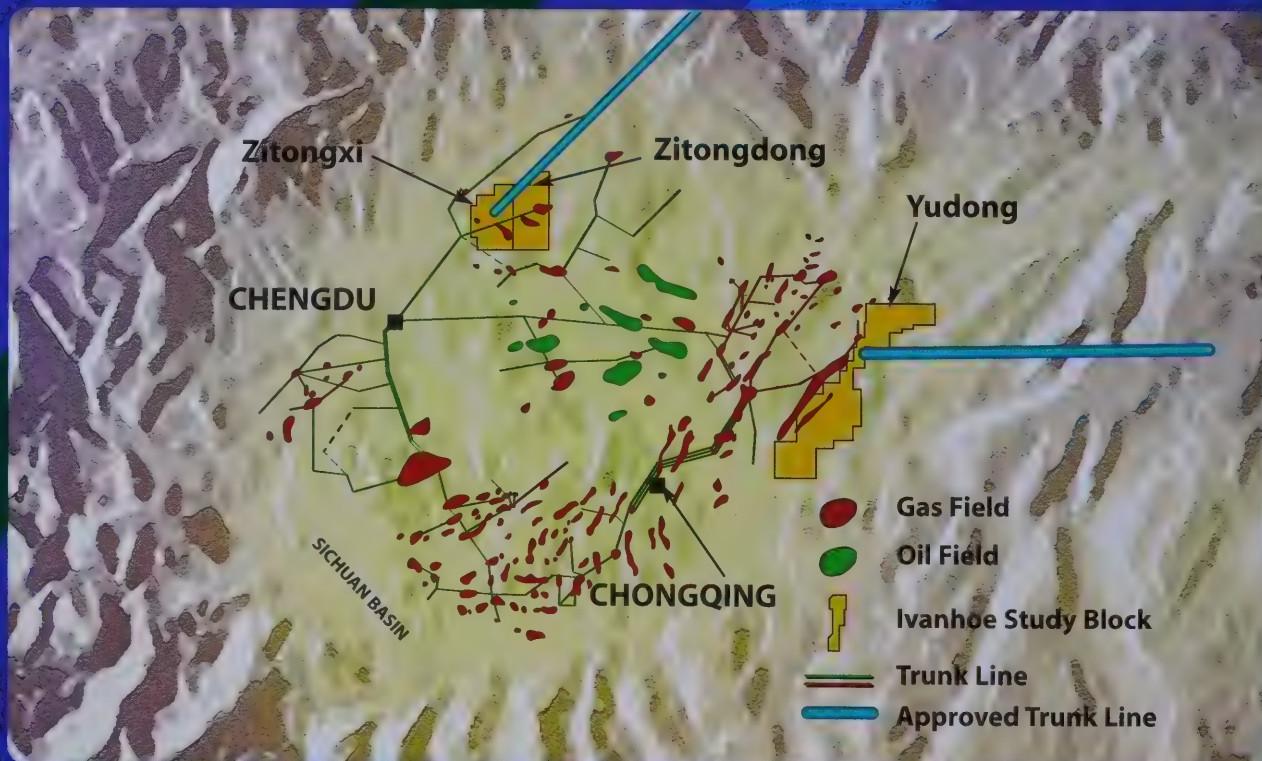
Artist concept of proposed Qatar GTL plant

China Properties

Ivanhoe has completed the evaluation of the enhanced oil recovery pilot programs we have been conducting at the Daqing and Dagang projects in China. While we are very encouraged with the increased production and reserve potential in both projects, we decided, following a review of our China strategies, to sell our interest in the smaller Daqing project. This action will free up manpower and management to concentrate on the larger Dagang project and our activities in Sichuan.

Sichuan Basin

In February 2001, we signed two memoranda of understanding with PetroChina Company Limited, a subsidiary of CNPC. These memoranda give us the exclusive right to negotiate petroleum contracts with PetroChina in three land blocks in Sichuan Province. We have agreed to carry out joint feasibility studies on the Zitongxi, Zitongdong and Yudong blocks located in the Sichuan Basin, approximately 930 miles southwest of Beijing. These blocks cover an area of approximately 2.2 million acres. PetroChina has drilled 39 wells on the three blocks with twenty-six of these wells classified as producing gas wells. PetroChina has only production tested eight of the estimated 38 hydrocarbon bearing structures located on these blocks. The entire Sichuan basin contains an estimated 245 TCF of gas, and annual production is approximately 270 billion cubic feet.



Using independent engineers, we continued to evaluate the data available from the wells drilled by the Chinese government and prepared a report that was submitted to PetroChina before the end of 2001. Information obtained from our evaluation and block review will be used to formulate a development plan, which in turn will be the basis for our discussions with PetroChina covering our exclusive arrangement in the three current areas of interest.



Dagang Project

At the Dagang project in 2001, we completed a successful pilot test phase during which we were able to produce our wells at rates about 300% higher than the existing wells nearby. During the fourth quarter, we produced more than 400 barrels of net oil per day. The crude is being sold for U.S. dollars to CNPC at approximately \$2.00 per barrel less than the West Texas Intermediate price. Based upon the results of the pilot test, Ivanhoe has submitted an overall development plan to Chinese regulatory authorities for their approval, which is expected during the first half of 2002. The development phase, scheduled to commence once all necessary approvals have been received, contemplates the investment of up to \$185 million to drill 115 new wells and to rework approximately 29 of the 82 existing wells over the next several years. Gross daily oil production rates are expected to grow to over 20,000 barrels per day. Under the contract, we will operate the project and fund 100% of the development costs to earn 82% of the net revenue until cost recovery, at which time our entitlement will be reduced to 49%. However, as with our oil developments in the U.S., we have the option of waiting for improved long-term crude prices before we commence the development phase at Dagang.



David Martin, Chairman

Part of the founding team at Occidental Petroleum, Mr. Martin was President & CEO of Occidental Oil & Gas Corporation, of California, from 1986 to 1996. He also was former Executive Vice-President and a director of Occidental Petroleum Corporation, and a Director of Canadian Occidental Petroleum. A geologist, with 39 years of international experience in the oil and gas industry, 26 of them in senior management positions with Occidental Petroleum Corporation.

Leon Daniel, President & CEO

A petroleum engineer and specialist in enhanced oil-recovery techniques, Mr. Daniel was formerly Executive Vice-President of Worldwide Business Development for Occidental Oil and Gas from 1996 to 1998 and President, Occidental Engineering Co., between 1993 and 1996. His 40 years of experience in the oil and gas industry include successful oil-field projects in Qatar, Venezuela, Libya, the North Sea, Colombia, Russia and the U.S.



Robert M. Friedland, Deputy Chairman

An international financier, and President of Ivanhoe Capital Corporation, Mr. Friedland has been associated with resource and technology ventures for 20 years. He was named Developer of the Year in 1996 by the Prospectors and Developers Association of Canada for his work in establishing and financing international mining and exploration companies, including Diamond Fields Resources, whose Voisey's Bay nickel deposit was sold to INCO Limited for CDN\$4.3 billion.

John Carver, Director

Mr. Carver, a petroleum geologist, was Senior Vice-President of Worldwide Exploration for Occidental Oil & Gas between 1994 and 1997. His 40 years of experience in the oil and gas industry include 25 years as a senior executive involved in international exploration for Occidental.



John O'Keefe, CFO

Mr. O'Keefe has nearly 30 years experience in the energy industry, which has included responsibilities for financial planning and analysis, investor relations, corporate finance, treasury, accounting and auditing. He is also Ivanhoe's Executive Vice-President of Investor Relations, and was formerly Vice-President, Investor Relations, with Santa Fe Snyder and Oryx Energy, both of Texas.



SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

- Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. For the fiscal year ended December 31, 2001.

or

- Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. For the transition period from _____ to _____.
Commission file number 000-30586

IVANHOE ENERGY INC.

(Exact name of registrant as specified in its charter)

Yukon, Canada

(State or other jurisdiction of incorporation or organization)

Not applicable

(I.R.S. Employer Identification No.)

**654 — 999 Canada Place
Vancouver, British Columbia, Canada
V6C 3E1**
(Address of principal executive offices)

(604) 688-8323

(Registrant's telephone number, including area code)

Securities to be registered pursuant to Section 12(b) of the Act: None

Securities registered or to be registered pursuant to Section 12(g) of the Act:

<u>Title of each class</u>	<u>Name of each exchange on which registered</u>
Common Shares, no par value	The Toronto Stock Exchange NASDAQ National Market

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

The aggregate market value of the voting stock held by non-affiliates of the Registrant on March 1, 2002 based on the closing price on the NASDAQ National Market on that date, was \$279,035,000.

Documents incorporated by reference: None

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CURRENCY AND EXCHANGE RATES

Unless otherwise specified, all reference to "dollars" or to "\$" are to United States dollars and all references to "Cdn. \$" are to Canadian dollars. The closing, low, high and noon buying rates in New York for cable transfers for the conversion of Canadian dollars into United States dollars for each of the four years ended December 31, 2001 as reported by the Federal Reserve Bank of New York were as follows:

	2001	2000	1999	1998	1997
Closing	\$0.6279	\$0.6669	\$0.6925	\$0.6504	\$0.6999
Low	\$0.6241	\$0.6410	\$0.6441	\$0.6341	\$0.6945
High	\$0.6697	\$0.6969	\$0.6925	\$0.7105	\$0.7487
Average Noon	\$0.6457	\$0.6730	\$0.6730	\$0.6714	\$0.7198

The average noon rate of exchange reported by the Federal Reserve Bank of New York for conversion of United States dollars into Canadian dollars on March 1, 2002 was \$0.6278 (\$1.00 = Cdn.\$1.5929). Exchange rates are based upon the noon buying rate in New York City for cable transfers in foreign currencies as certified for customs purposes by the Federal Reserve Bank of New York.

ABBREVIATIONS

As generally used in the oil and gas business and in this Annual Report, the following terms have the following meanings:

Boe	= barrel of oil equivalent	MMBI/d	= million barrels per day
Bbl	= barrel	MMBtu	= million British thermal units
MBbl	= thousand barrels	Mcf	= thousand cubic feet
MMBbl	= million barrels	MMcf	= million cubic feet
Bbl/d	= barrels per day	Mcf/d	= thousand cubic feet per day
MBbl/d	= thousand barrels per day	MMcf/d	= million cubic feet per day

When we refer to oil in "equivalents," we are doing so to compare quantities of oil with quantities of gas or to express these different commodities in a common unit. In calculating Bbl equivalents, we use a generally recognized standard in which one Bbl is equal to six Mcf.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this document are "forward-looking statements". Such forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause our actual results, performance or achievements, or other future events, to be materially different from any future results, performance or achievements or other events expressly or implicitly predicted by such forward-looking statements. Such risks, uncertainties and other factors include, but are not limited to, our short history of limited revenue, losses and negative cash flow from our current exploration and development operations in the United States and China; our limited cash resources and consequent need for additional financing; uncertainties regarding the potential success of our oil and gas exploration and development projects in the United States and China; uncertainties regarding the potential success of gas-to-liquids technology; oil price volatility; oil and gas industry operational hazards and environmental concerns; government regulation and requirements for permits and licenses, particularly in the foreign jurisdictions in which we carry on business; title matters; risks associated with carrying on business in foreign jurisdictions; conflicts of interests; competition for a limited number of promising oil and gas exploration properties from larger more well financed oil and gas companies; and other statements contained herein regarding matters that are not historical facts. Forward-looking statements can often be identified by the use of forward-looking terminology such as "may", "will", "expect", "intend", "estimate", "anticipate", "believe" or "continue" or the negative thereof or variations thereon or similar terminology.

ENFORCEABILITY OF CIVIL LIABILITIES

We have been organized under the laws of Canada and our executive offices are located in British Columbia, Canada. Some of our directors, controlling persons and officers and representatives of the experts named in this Form 10-K Annual Report reside outside the United States and a substantial portion of their assets and our assets are located outside the United States. As a result, it may be difficult for you to effect service of process within the United States upon the directors, controlling persons, officers and representatives of experts who are not residents of the United States or to enforce against them judgments obtained in the courts of the United States based upon the civil liability provisions of the federal securities laws or other laws of the United States. There is doubt as to the enforceability in Canada against us or against any of our directors, controlling persons, officers or experts who are not residents of the United States, in original actions or in actions for enforcement of judgments of United States courts, of liabilities based solely upon civil liability provisions of the U.S. federal securities laws. Therefore it may not be possible to enforce those actions against us, our directors and officers or experts named in this Form 10-K Annual Report.

RISK FACTORS

We are subject to a number of risks due to the nature of the industry in which we operate, the present state of development of our business and the foreign jurisdictions in which we carry on business. The following factors contain certain forward-looking statements involving risks and uncertainties. Our actual results may differ materially from the results anticipated in these forward-looking statements.

We have a history of losses and must generate greater revenue to achieve profitability.

We commenced operations in 1997 and have been involved in two start-up situations in Russia and the United States. Like most start up companies we have incurred losses during our start up activities. Our current revenues are insufficient to fund our medium and long-term business plans.

We might not be successful in acquiring and developing new prospects and our exploration and development properties may not contain any significant proved reserves.

Our future success depends upon our ability to find, develop and acquire additional economically recoverable oil and natural gas reserves. The successful acquisition and development of oil and gas properties requires proper forecasting of:

- an assessment of recoverable reserves,
- future oil and gas prices and operating costs,
- potential environmental and other liabilities, and
- productivity of new wells drilled.

These assessments are inexact. As a result, we might not recover the purchase price of a property from the sale of production from the property, or might not recognize an acceptable return from properties we acquire. Our estimates of exploration, development and production costs can be affected by such factors as:

- permitting regulations and requirements,
- weather, environmental factors,
- unforeseen technical difficulties, and
- unusual or unexpected formations, pressures and work interruptions.

Exploration and development involves significant risks. Few wells which are drilled are developed into commercially producing fields. Substantial expenditures may be required to establish the existence of proved reserves, and we cannot assure you that commercial quantities of oil and gas deposits will be discovered sufficient to enable us to recover our exploration and development costs or be sufficient to sustain our business.

Expansion of our operations will require significant capital expenditures for which we may be unable to provide sufficient financing. Our need for additional capital may harm our financial condition.

We will be required to make substantial capital expenditures to develop our existing reserves and to discover new oil and gas reserves. Historically, we have relied, and continue to rely, on external sources of financing to meet our capital requirements, to continue acquiring, exploring and developing oil and gas properties and to otherwise implement our corporate development and investment strategies. We have, in the past, relied upon equity capital as our principal source of funding. In October 2001, we completed approximately \$18 million in equity financing. We plan to obtain the future funding we will need through debt and equity markets, but we cannot assure you that we will be able to obtain additional funding when it is required. We also make offers to acquire oil and gas properties in the ordinary course of our business. If these offers are accepted, our capital needs may increase substantially. If we fail to obtain the funding that we need when it is required, we may have to forego or delay potentially valuable opportunities to acquire new oil and gas properties or default on existing funding commitments to third parties and forfeit or dilute our rights in existing oil and gas property interests. Our limited operating history may make it difficult to obtain future financing.

You should not unduly rely on reserve information because reserve information represents estimates.

Estimates of oil and natural gas reserves involve a great deal of uncertainty, because they depend in large part upon the reliability of available geologic and engineering data, which is inherently imprecise. Geologic and engineering data are used to determine the probability that a reservoir of oil and natural gas exists at a particular location, and whether oil and natural gas are recoverable from a reservoir. Recoverability is ultimately subject to the accuracy of data regarding, among other factors:

- geological characteristics of the reservoir structure,
- reservoir fluid properties,
- the size and boundaries of the drainage area, and
- reservoir pressure and the anticipated rate of pressure depletion.

The evaluation of these and other factors is based upon available seismic data, computer modeling, well tests and information obtained from production of oil and natural gas from adjacent or similar properties, but the probability of the existence and recoverability of reserves is less than 100% and actual recoveries of proved reserves usually differ from estimates.

Estimates of oil and natural gas reserves also require numerous assumptions relating to operating conditions and economic factors, including, among others:

- the price at which recovered oil and natural gas can be sold,
- the costs associated with recovering oil and natural gas,
- the prevailing environment conditions associated with drilling and production sites,
- the availability of enhanced recovery techniques,
- the ability to transport oil and natural gas to markets, and
- governmental and other regulatory factors, such as taxes and environmental laws.

A change in any one or more of these factors could result in known quantities of oil and natural gas previously estimated as proved reserves becoming unrecoverable. For example, a decline in the market price of oil or natural gas to an amount that is less than the cost of recovery of such oil and natural gas in a particular location could make production thereof commercially impracticable. The risk that a decline in price could have that effect is magnified in the case of reserves requiring sophisticated or expensive production enhancement technology and equipment, such as some types of heavy oil. Each of these factors, by having an impact on the cost of recovery and the rate of production, will also affect the present value of future net cash flows from estimated reserves.

In addition, estimates of reserves and future net cash flows expected from them prepared by different independent engineers, or by the same engineers at different times, may vary substantially.

Information in this document regarding our future exploitation projects reflects our current intent and is subject to change.

We describe our current exploration and development plans in this document. Whether we ultimately implement our plans will depend on the following factors:

- availability and cost of capital,
- receipt of additional seismic data or the reprocessing of existing data,
- current and projected oil or gas prices,
- the costs and availability of drilling rigs and other equipment supplies and personnel necessary to conduct these operations,
- success or failure of activities in similar areas,
- changes in the estimates of the costs to complete the projects,
- our ability to attract other industry partners to acquire a portion of the working interest to reduce costs and exposure to risks, and
- decisions of our joint working interest owners.

We will continue to gather data about our projects and it is possible that additional information will cause us to alter our schedule or determine that a project should not be pursued at all. You should understand that our plans regarding our projects might change.

Our business may be harmed if we are not able to retain our licenses, leases and working interests in licenses and leases.

Some of our properties are held in the form of licenses and leases and working interests in licenses and leases. If we or the holder of the license or lease fails to meet the specific requirements of each license or lease, the license or lease may terminate or expire. We cannot assure you that any of the obligations required to maintain each license or lease will be met. The termination or expiration of our licenses or leases or our working interest relating to a license or lease may harm business. Some of our property interests will terminate unless we fulfill certain obligations under the terms of our agreements related to such properties. If we are not able to satisfy these conditions on a timely basis, we may lose our rights in these properties. The termination of our interests in these properties may harm our business.

We are not able to guarantee the successful commercial development of our licensed "gas-to-liquids" technology.

To date, no commercial-scale gas-to-liquids ("GTL") plants have been constructed using the proprietary GTL process we license from Syntroleum Corporation ("Syntroleum") and, therefore, the process has not been proven on a commercial scale. Other commercial developers of GTL technology include Exxon Mobil, Shell and Sasol, each of which has significant financial resources and may be able to use its greater financial flexibility to commercialize their GTL technologies and commence production of GTL products earlier than we and Syntroleum can, thereby obtaining a potential competitive advantage. This advantage may prove to be particularly important as GTL project developers compete to obtain the most attractive stranded natural gas deposits to provide feedstock for their plants.

Crude oil and natural gas prices are volatile.

Fluctuations in the prices of oil and natural gas will affect many aspects of our business, including:

- our revenues, cash flows and earnings,
- our ability to attract capital to finance our operations,
- our cost of capital,
- the amount we are able to borrow, and
- the value of our oil and natural gas properties.

Both oil and natural gas prices are extremely volatile. Oil prices are determined by international supply and demand. Political developments, compliance or non-compliance with self-imposed quotas, or

agreements between members of the Organization of Petroleum Exporting Countries can affect world oil supply and prices. Any material decline in prices could result in a reduction of our net production revenue and overall value. The economics of producing from some wells could change as a result of lower prices. As a result, we could elect not to produce from certain wells. Any material decline in prices could also result in a reduction in our oil and natural gas acquisition and development activities.

In addition, a material decline in oil and natural gas prices from historical average prices could adversely effect our ability to borrow and to obtain additional capital on attractive terms.

Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploration projects.

Government regulations in foreign countries may limit our activities and harm our business operations.

In addition to our interest in our China project, we may enter into contractual arrangements to acquire oil and gas properties in other foreign jurisdictions with governments, governmental agencies or government-owned entities. The foreign legal framework for these agreements, particularly in developing countries, is often based on recent political and economic reforms and newly enacted legislation, which may not be consistent with long-standing local conventions and customs. As a result, there may be ambiguities, inconsistencies and anomalies in the agreements or the legislation upon which they are based which are atypical of more developed western legal systems and which may affect the interpretation and enforcement of our rights and obligations and those of our foreign partners. Local institutions and bureaucracies responsible for administering foreign laws may lack a proper understanding of the laws or the experience necessary to apply them in a modern business context. Foreign laws may be applied in an inconsistent, arbitrary and unfair manner and legal remedies may be uncertain, delayed or unavailable.

We may not be successful in negotiating additional production sharing contracts in China.

We hold our interest in our China project through a production sharing contract with China National Petroleum Corporation ("CNPC"). We also have two memoranda of understanding with CNPC's subsidiary, PetroChina Corporation ("PetroChina"), indicating a mutual intention to negotiate additional production sharing contracts. We cannot assure you, based on our existing memoranda of understanding with PetroChina, that we will successfully negotiate additional production sharing contracts. It is possible that disputes between us could arise in the future, which must be resolved under foreign law. We cannot be sure that we can enforce our legal rights in foreign countries or that an effective legal remedy will be available to us in any dispute governed by foreign law.

Complying with environmental and other government regulations could be costly and could negatively impact our production.

Our operations are governed by numerous laws and regulations at various levels of government in the countries in which we operate. These laws and regulations govern the operation and maintenance of our facilities, the discharge of materials into the environment and other environmental protection issues. The laws and regulations may, among other potential consequences:

- require that we acquire permits before commencing drilling,
- restrict the substances that can be released into the environment in connection with drilling and production activities,
- limit or prohibit drilling activities on protected areas such as wetlands or wilderness areas,
- require that reclamation measures be taken to prevent pollution from former operations,
- require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells and remediating contaminated soil and groundwater, and

- require remedial measures be taken with respect to property designated as a contaminated site, for which we are a responsible person.

Under these laws and regulations, we could be liable for personal injury, clean-up costs and other environmental and property damages, as well as administrative, civil and criminal penalties. We maintain limited insurance coverage for sudden and accidental environmental damages as well as environmental damage that occurs over time. However, we do not believe that insurance coverage for the full potential liability of environmental damages is available at a reasonable cost. Accordingly, we could be liable, or could be required to cease production on properties, if environmental damage occurs.

The costs of complying with environmental laws and regulations in the future may harm our business. Furthermore, future changes in environmental laws and regulations could occur that result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, any of which could have a material adverse effect on our financial condition or results of operations.

We compete for oil and gas properties with many other exploration and development companies throughout the world who have access to greater financial, technical and human resources.

We operate in a highly competitive environment in which we compete with other exploration and development companies to acquire a limited number of prospective oil and gas properties. Many of our competitors are much larger than we are and have greater financial, technical and human resources than we do and, as a result, enjoy a competitive advantage. They may be able to pay more for productive oil and gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial, technical and human resources permit.

Our share ownership is highly concentrated and, as a result, our principal shareholders control our business.

Our directors and executive officers, including Robert M. Friedland, collectively own or have rights to acquire approximately 36% of our common stock and control our Board of Directors and determine our policies, business and affairs and the outcome of any corporate transaction or other matter, including mergers, consolidations and the sale of all or substantially all of our assets.

In addition, the concentration of our ownership may have the effect of delaying, deterring or preventing a change in control that otherwise could result in a premium in the price of our common stock.

If we lose our key management and technical personnel, our business may suffer.

We rely upon a relatively small group of key management and technical personnel. We do not maintain any key man insurance. We do not have employment agreements with certain of our key management and technical personnel and we cannot assure you that these individuals will remain with us in the future. An unexpected partial or total loss of their services would harm our business.

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

CORPORATE OVERVIEW

We are an international energy company engaged in conventional oil exploration and production, enhanced oil recovery projects and the development of gas-to-liquids projects. We were incorporated pursuant to the laws of the Yukon Territory, Canada, on February 21, 1995 under the name 888 China Holdings Limited. We were largely inactive until early 1996. On June 3, 1996, we changed our name to Black Sea Energy Ltd., and on June 24, 1999, we changed our name to Ivanhoe Energy Inc.

Our authorized capital consists of an unlimited number of common shares without par value and an unlimited number of preferred shares without par value.

Our principal executive offices are located at Suite 654 — 999 Canada Place, Vancouver, British Columbia, V6C 3E1, and our registered and records offices are located at 300-204 Black Street, Whitehorse, Yukon, Y1A 2M9.

OVERVIEW OF THE BUSINESS

Ivanhoe Energy Inc. is a company focused on three major strategies: (1) production of synthetic fuels from natural gas using gas-to-liquids ("GTL") technology; (2) conventional exploration and production ("E&P"), primarily natural gas in the United States; and (3) enhanced oil recovery ("EOR") and natural gas projects, on a production-sharing basis, with national petroleum companies.

Following our incorporation in February, 1995, we were largely inactive until early 1996, when we commenced our business as an acquirer, explorer and developer of oil and gas properties. Initially, we concentrated our efforts on acquiring oil and gas properties in Russia. Our strategy was to seek out existing oil and gas properties in Russia on which past drilling and field development practices did not maximize reserve recoveries and to establish joint ventures with local partners to rehabilitate existing wells to recover additional production. We achieved great success with our development and rehabilitation activities at our Kalchinskoye field joint venture project in western Siberia. However a dispute with our joint venture partner which commenced in May 1998, prevented us from proceeding with our operations in the area. In August 2000 we settled our dispute and disposed of our Russian assets for approximately \$29 million, bringing to an end our activities in Russia.

In the third quarter of 1998, we began to implement a diversification program aimed at expanding the geographical scope of our business beyond Russia. We added three individuals to our Board of Directors who have international experience in the oil and gas industry. David Martin, who is now our Chairman, was formerly the President and Chief Executive Officer of Occidental Oil & Gas Corporation. E. Leon Daniel, who is now our President and Chief Executive Officer, and John Carver, who is now one of our directors, are also both former executives of Occidental Oil & Gas Corporation. In August, 1998, we began acquiring oil and gas exploration property interests in Peru (which we relinquished in 2000) and California. In 1999, we acquired property interests in China. In April, 2000 we acquired a limited volume license from Syntroleum, to use its proprietary GTL technology to convert natural gas into synthetic fuels. We subsequently upgraded our limited volume license to a master license without volume limitations. In May, 2000, we began acquiring interests in oil and gas exploration properties in Texas and in March 2001, we acquired interests in oil and gas exploration properties in Kentucky.

In California, we have been accumulating working interests and royalty interests in the San Joaquin Valley since 1998, primarily through an exploration agreement with Aera Energy LLC ("Aera"), which entitled us to explore and identify oil and gas prospects in the San Joaquin Valley using exploration, seismic and technical data owned by Aera. See "Oil and Gas Properties — California"

In June, 1999, we further expanded the geographical scope of our business into China by acquiring Sunwing Energy Ltd. ("Sunwing"), an oil and gas company. As a result of our acquisition of Sunwing, we acquired two production sharing contracts with CNPC to develop and operate the Kongnan oilfield in Dagang, located in Hebei Province and the Zhaozhou oilfield in Daqing, located in Heilongjiang Province. See "Oil and Gas Properties — China". In February 2001, we entered into two memoranda of understanding with PetroChina Company Limited, ("PetroChina") a subsidiary of CNPC, which gives us the exclusive right to negotiate petroleum contracts for the development of oil and gas reserves in three blocks in the Sichuan Basin. The Sichuan Basin is a major oil and gas producing region of China located approximately 930 miles southwest of Beijing. We are undertaking feasibility studies on the three blocks. If the results are positive, we will commence negotiating production sharing contracts.

In May, 2000, we entered into an agreement with Discovery Operating, Inc. ("Discovery") to earn working interests ranging from 40% to 96% (reducing to between 32% and 77% after pay out) in approximately 10,000 gross acres of oil and gas exploration property in the Spraberry Trend of the West Texas Permian Basin in Midland County, Texas. During 2000 and 2001 we leased the mineral rights in 48,250 gross acres in the Bossier gas sands in east Texas and in 2001 entered into a joint venture agreement with a

subsidiary of Unocal Corp. ("Unocal") to explore and develop prospects in the Bossier Trend. See "Oil and Gas Properties — Texas".

In 2001, the Company acquired a 50% working interest in an exploration project in the Rome Trough in Kentucky. See "Oil and Gas Properties — Kentucky".

The master license we acquired from Syntroleum allows us to use Syntroleum's proprietary process to convert natural gas into synthetic oil, transportation fuels and other synthetic petroleum products. We plan to use the technology in areas with large natural gas deposits, which would otherwise be uneconomic to develop. Our master license entitles us to use the Syntroleum proprietary process in an unlimited number of gas-to-liquids projects throughout the world (excluding North America, China and India).

We are actively pursuing development and production sharing contracts for GTL plants in both Qatar and Egypt and have undertaken feasibility studies during 2001 in connection with these opportunities. We have also agreed in principle to become a partner in Syntroleum's Sweetwater GTL project in Western Australia. To date, we have invested \$2 million. Subject to certain conditions, including Syntroleum's obligation to arrange project financing, we may invest an additional \$19 million to become a 13% equity partner in the project. See "Gas-to-Liquids Projects".

CORPORATE STRATEGY

Our goal is to create a diversified global energy company focused on GTL, E&P and EOR. We believe we can successfully implement our strategy and position ourselves to compete over the longer term in what we expect will be a rapidly evolving energy industry.

Our business plan is multi-faceted and involves the pursuit of objectives with short, medium and long term impacts on our business. Our short-term objective is to focus on areas where production can be achieved quickly and efficiently to create cash flow to fund our operations and allow us to pursue our medium and long-term objectives. To date, we have established production in the Spraberry Trend of West Texas and at South Midway Sunset in the San Joaquin Basin of California. Sunwing has also established production at its Dagang project in China as part of its completed pilot-test program.

The cornerstone of our medium term strategy is deep gas exploration in the San Joaquin Basin of California and in the Bossier gas sands of east Texas. Since 1999 we have accumulated substantial acreage in the San Joaquin Basin. We are in the process of interpreting an 80,000 acre three-dimensional seismic survey along the west side of the San Joaquin Valley which we are using to identify drilling targets. In August 2001, we spud our first deep gas exploration well in the Northwest Lost Hills area of the San Joaquin Basin with our partner, Aera as the operator. In November 2001 we spud our first well in the Cresslen Ranch prospect in the Bossier gas sands of east Texas with our partner Unocal.

We continue to pursue our enhanced oil recovery initiatives in China and larger natural gas project opportunities under our Sichuan memoranda of understanding with PetroChina. We remain encouraged by the results achieved in our pilot program at Dagang and intend to proceed with the development phase of the project once our development plan is approved by Chinese government authorities. Based on our decision to concentrate on larger projects in China, we decided to dispose of our smaller Daqing project. See "Oil and Gas Properties — China". We also are seeking other opportunities in China and elsewhere to acquire interests in fields with economic development potential.

Our long-term objective is to become a leader in the development and operation of GTL projects. We foresee rapidly increasing future demand for clean energy as environmental regulations become more stringent and the world's crude oil becomes more sour and heavy. We believe that Syntroleum's proprietary GTL technology holds significant potential for the economic production of synthetic fuels and other specialty petroleum products from stranded natural gas deposits throughout the world, which would otherwise be uneconomic to exploit. Although there are several competing GTL technologies under development, we believe that the Syntroleum technology offers several key advantages. Plant

construction is less expensive and the plant is safer to operate because, unlike competing technologies, it uses compressed air rather than oxygen.

With our master license to use Syntroleum's proprietary GTL technology, we are currently pursuing opportunities in Qatar and Egypt to obtain rights to stranded natural gas deposits to use as feedstock for gas-to-liquids projects. We believe that synthetic fuels and specialty products produced using GTL processes will eventually present an attractive, economic and environmentally superior alternative to traditional fuels derived from crude oil.

GAS-TO-LIQUIDS PROJECTS

Syntroleum License

We hold a non-exclusive master license entitling us to use Syntroleum's proprietary GTL process in an unlimited number of projects in all areas of the world (other than North America, China and India) with unlimited production volume restrictions.

Syntroleum Process

Syntroleum's proprietary GTL process is designed to catalytically convert natural gas into synthetic liquid hydrocarbons. This process (the "Syntroleum Process") is designed to substantially reduce the capital and operating cost and the minimum economic size of a GTL plant.

Syntroleum developed its GTL technology based on a process developed in Germany in the 1920s for the gasification of coal into oil, called the Fischer-Tropsch reaction. Syntroleum has applied its principles to the conversion of natural gas to synthetic liquid hydrocarbons. Syntroleum believes that it holds a competitive advantage over other GTL technologies because the Syntroleum Process compresses air directly from the atmosphere when converting natural gas into synthetic hydrocarbons. The GTL processes developed by Syntroleum's competitors use either steam reforming or a partial combination of steam reforming and partial oxidation with pure oxygen. A steam reformer and an air separation plant necessary for oxidation are bulky, expensive and increase operating costs. The Syntroleum Process allows for the operation of GTL plants without an air separation plant or steam reformer, thereby reducing capital costs, operating costs, the size and complexity of a GTL plant and operating volatility.

From our perspective, the greatest opportunity for the use of the Syntroleum Process lies in the extraction of stranded natural gas. Stranded natural gas exists in known reservoirs, which cannot be marketed on an economic basis. Operators consider natural gas to be stranded based on the relative size of the fields, the location of the natural gas relative to its market and the cost to transport the natural gas to markets.

GTL Prospects

During 2001 we undertook detailed project feasibility studies for the construction, operation and cost of GTL plants in both Qatar and Egypt. The study for Qatar examined the potential for development of offshore natural gas, conveyance of natural gas to shore and its subsequent dehydration, gas liquids extraction through a natural gas liquids plant with production capacity of up to 185,000 barrels per day, product storage and offloading facilities. The study also examined four alternative plant designs. The first was a maximum efficiency case in which production was maximized. A second case considered the same GTL production efficiency with supplemental power and water being manufactured from the waste heat. A third case addressed maximum efficiency with maximized water production. The fourth case focused on maximized power and water manufacture for export. All cases were required to address the various needs of the host government and will be further evaluated during currently ongoing commercial discussions with Qatari authorities.

While many of the issues addressed in the feasibility studies we have undertaken for Qatar are also applicable to Egypt, the feasibility studies we have undertaken for Egypt contemplate the natural gas feedstock being purchased, rather than developed, and production capacity in the order of 90,000

barrels per day. The results of the feasibility studies for Egypt will be utilized during the course of commercial discussions with Egyptian authorities, which we have yet to formally initiate.

We have conducted marketing and transportation feasibility studies for both Europe and Asia Pacific regions in which we identified potential markets and estimated premiums for GTL diesel and naphtha. We have also recently undertaken a commercialization study in Japan in conjunction with Inpex Corporation and Mitsui & Co. Ltd., of Japan, and Qatar Petroleum to study the role that Japanese companies can play as purchasers of GTL and natural gas liquids products and as suppliers of equipment, materials, services and project financing. We plan to use the results of these studies as the basis for evaluating the commerciality of our GTL opportunities.

Sweetwater GTL Project

In 2000, we signed a letter of intent to invest \$21 million to participate as a 13% partner in Syntroleum's Sweetwater GTL project in Western Australia. The project is a 10,000 barrels per day plant that will produce specialty products such as lubricants, industrial fluids and liquid normal paraffins, as well as synthetic fuels. We made a \$2 million advance for front-end engineering and other costs. The balance of the investment is subject to a number of conditions, including Syntroleum's obligation to arrange project financing.

Syntroleum has made progress in developing the project but continues to seek financing. We have since identified two larger GTL project opportunities in Qatar and Egypt, which may affect our continuing participation in Sweetwater but no decision has been reached at this time.

OIL AND GAS PROPERTIES

Our primary oil and gas properties are located in the San Joaquin Valley area of California. We also hold interests in exploration and development properties in Texas and Kentucky in the United States and in Hebei Province in China. Set forth below is a description of our material oil and gas properties.

California

Over the past four years, we have acquired interests in a number of properties in and around the San Joaquin Basin area of Southern California. To date, only our South Midway Sunset project contains proved reserves and has wells on production. We cannot assure you that any of our other prospects in California will result in the development of commercially viable production.

Aera Exploration Agreement

In 1998, we acquired rights to an exploration agreement with Aera covering an area of more than 250,000 acres in the San Joaquin Valley. The Aera exploration agreement gave us access to all of Aera's exploration, seismic and technical data in the region for the purpose of identifying drillable exploration prospects within the exclusive area. We have a right to a working interest ownership in the drillable prospects in which Aera elects to participate and Area has the right to act as the operator for any drillable prospects in which it elects to participate.

Except for those prospect areas of mutual interest ("AMIs") previously designated by us and accepted by Aera, our exclusive rights to explore Aera's properties expired in September 2001. We will continue to hold exploration rights to the lands within previously designated and accepted prospect AMIs until an exploration well is drilled in that prospect and the prospect has been evaluated. Although the Aera exploration agreement provides that Aera's working interest in these prospects will range from a minimum of 25% to a maximum of 87.5%, we have negotiated different working interest allocations with Aera on a prospect basis. Aera is obliged to assign to us any working interest in the prospect that it does not retain. Once we identify a drillable prospect and agree upon working interests with Aera, we have an indefinite time to carry out exploration drilling if Aera elects to participate in the prospect. If Aera elects to participate but not to drill the designated prospect, or elects not to participate, we have

an additional two years to drill the prospect on our own or with other parties. This two-year period will be extended as long as we continue to drill or have established production.

The properties covered by the Aera exploration agreement are located in Kern, Kings, Tulare, Fresno, San Benito, Monterey and San Luis Obispo Counties. Using the extensive proprietary seismic and technical databases owned by Aera and supplemented by us, we have identified over forty prospects within 18 prospect AMIs covering approximately 72,800 acres. Of the 18 prospect AMIs we have submitted, Area has elected to take a working interest in 12 areas: Diamond, Northwest Lost Hills, Amethyst, Belgian Anticline, Emerald, Sapphire, Ruby, North Basil, Cinnamon, Sage, Nutmeg and Rosemary, in which we have working interests ranging from 12.5% to 50%. Aera has yet to make an election on two submitted prospect AMIs: Jacaranda and Coles Levee. We have a 100% working interest in the three prospect AMIs in which Aera elected not to participate. One of these prospects is South Midway Sunset on which we have, to date, drilled 29 successful wells. The second prospect AMI is Citrus and the third is North Yowlumne where we are planning to obtain 3-D seismic. Neither we nor Aera plan to participate in the Kern River AMI and we have farmed out this AMI and retained an overriding royalty interest. We have relinquished our interests in all other Aera exploration agreement properties.

Set forth below is a description of our material exploration and development activities under the Aera exploration agreement.

- *Northwest Lost Hills*

Our first deep-gas exploration well in the San Joaquin Valley, known as the Aera/Ivanhoe Northwest Lost Hills #1-22 well located in Kern county, was spud in August 2001. The well was drilled to a depth of 18,400 feet and encountered the top of the targeted Temblor formation. Prior to the setting of casing, we determined, based on geological information, that the bottom hole could be placed in a more structurally favorable location so we sidetracked the well and we are currently setting casing down to approximately 17,000 feet. The target depth of the well is 20,000 feet. The well lies five miles northwest of, and on a trend with, the Bellevue No. 1 blowout well, drilled by Berkley Petroleum Corp. (later acquired by Anadarko Petroleum Corporation), which was a Temblor gas discovery. In the 9,600 gross acres owned and under option encompassing the Northwest Lost Hills prospect, we hold on average a 39% working interest. We have a 42% working interest in the Aera/Ivanhoe Northwest Lost Hills #22-1 well.

- *Amethyst*

We have identified a prospect in the northern part of the South Belridge area where we currently hold a 12.5% working interest. We originally expected to commence drilling the prospect in late 2001, but delayed drilling in order to shoot additional modern 2-D seismic, which we are currently interpreting. We now expect to drill during the second quarter of 2002.

- *Diamond*

We have completed a 3-D seismic survey covering the majority of this prospect and we are continuing to interpret the results. We currently have a minimum working interest of 12.5% in this prospect.

- *Belgian Anticline*

We identified a drillable prospect on the western flank of the Belgian Anticline area and spudded a well late in 2000. We encountered three potential hydrocarbon-bearing zones but two of the zones we tested were not capable of commercial production. Our testing of the third zone was inconclusive due to technical difficulties. Aera is currently processing some additional geophysical information and we are awaiting Aera's recommendation. We hold a 40% working interest in the prospect and Aera holds the balance.

- *South Midway Sunset*

By the end of 2001, we had drilled 31 wells in the South Midway field, 29 of which are producing oil at commercial rates. We are currently producing approximately 400 net barrels of oil per day. In the fourth quarter of 2001 we completed a pilot cyclic steam project, which was successful in more than doubling production rates in the five wells that we treated. We are now planning a full scale cyclic steam project to commence in 2002. South Midway provides us with immediate cash flow from a low risk, low cost development project with existing infrastructure. We own a 100% working interest and a 93% net revenue interest in the project. Aera elected not to participate in this project but receives royalties pursuant to the Aera exploration agreement.

- *Citrus*

We have deferred drilling a well in this prospect until we can find a partner to participate in the funding of the drilling and until gas and oil prices stabilize. We own a 100% working interest in the prospect.

- *Emerald, Sapphire and Ruby*

We have a 12.5% working interest in each of these three prospects. We are planning to drill an exploration well in the Emerald prospect in the fourth quarter of 2002. Our plans for exploration activities in Sapphire and Ruby will depend on the results of the Emerald well.

- *North Basil, Cinnamon, Sage, Nutmeg and Rosemary*

We have a 50% working interest in each of these five prospects. Depending on the results of the Aera/Ivanhoe Northwest Lost Hills #1-22 well, we may drill an exploration well on one of these prospects in 2002.

Other Southern California

North South Forty

In September 15, 1999, we entered into an agreement with Prime Natural Resources, LLC ("Prime") to jointly conduct a 3-D seismic survey in the southern San Joaquin Valley basin in order to identify new prospects over an area of approximately 80,000 acres. We subsequently entered into an exploration agreement with Prime and Aera in which we agreed to pool certain of our acreage positions in the basin to share the costs of carrying out the 3-D seismic program and to broaden our respective interests in the area. The pooled acreage under the agreement is divided into four areas called North South Forty Areas A, B, C and D. Each party retains an equal interest in the data generated from the 3-D seismic program, except Aera retains an interest in only the data generated in areas A and B. All costs of carrying out the program will be borne equally by Prime and us. Our working interests range from 17.5% to 50% in these four areas. The 3-D seismic program is intended to identify prospects for exploration drilling. Once prospects have been identified, each party may elect to participate in a drilling program. We started evaluating the results of the program in the second half of 2001 and our evaluation remains ongoing.

Magic Mountain / OroFino

Our NL&F Magic Mountain #1 well in Los Angeles county and our OroFino well in San Luis Obispo county were drilled in 2001, were unsuccessful at finding commercial hydrocarbons and abandoned. Neither prospect was in the San Joaquin Valley or part of the Aera exploration agreement.

Texas

Spraberry

In April 2000, we entered into an agreement with Discovery relating to approximately 10,000 gross acres of oil and gas exploration property in the Spraberry Trend of the West Texas Permian Basin in Midland

County. Under the terms of our agreement, we hold, until payout of our costs, a 96.15% working interest (77% after payout) in the first four wells and a 62.5% working interest (50% after payout) in the remaining wells on approximately 7,900 gross acres. We hold a 40% working interest (32% after payout) on approximately 1,700 gross acres covered by a farm-out agreement. Discovery is the operator.

As of the end of 2001 we drilled 30 wells in the Spraberry field, which are currently producing approximately 300 net barrels of oil equivalent per day. All 30 wells have been completed in one or more of the Wolfcamp zones. However, 5 wells still are awaiting their Spraberry zone completions. We plan to start these completions in early 2002 and finish them by the end of 2002. During 2002, we may also drill an additional six to eight wells in the area known as Apache Flats where we have a 40% working interest before payout. To date we have drilled three wells in this area and each is producing approximately 40 net barrels of oil equivalent per day.

Further field development has been curtailed pending results from our planned activities and stabilizing of commodity prices.

Bossier

We have leased mineral rights in 58,000 gross (44,000 net) acres in the Bossier Trend in east Texas under a joint venture with Unocal. Eight prospects have been identified within this acreage. Unocal is the operator of the joint venture and will fund the drilling costs for the first several exploration wells to offset the \$10 million in leasehold, seismic and processing costs we have already incurred. After our respective investments in the joint venture have been equalized we will share exploration, development and infrastructure costs equally.

Two wells were spud in the Cresslen Ranch prospect. The 1-Trinity Materials well was drilled to a depth of 12,240 feet and encountered approximately 120 net feet of Bossier sand, which indicates the potential for natural gas production. The 2-Trinity Materials well was drilled to a depth of 11,583 feet and also encountered approximately 220 feet of net Bossier sand. We have commenced fracturing operations and expect to test the well shortly. We plan to drill several additional wells in the Bossier trend by the end of 2002. Our working interest in the Bossier sands is subject to leasehold burdens and a 9.375% net profit interest.

Kentucky

In March of 2001 we entered into a joint venture with Hay Exploration, Inc. to explore for natural gas in the Rome Trough of eastern Kentucky. We each hold a 50% interest. We have identified three prospect areas covering 15,000 net acres and during 2001 we drilled an exploration well in each prospect area. One well was suspended pending further evaluation. Preliminary analysis of the drilling logs for the remaining two wells indicates several potential gas pay zones. Inclement weather and unavailability of completion rigs has delayed the testing of these two wells. The wells were perforated early in 2002 and we plan to fracture stimulate both wells in the near future.

China

We hold interests in China through our wholly owned subsidiary Sunwing.

Dagang Project

Our principal asset in China is a 20-year production sharing contract with CNPC, covering an area of 22,400 gross acres divided into six blocks in the Kongnan oilfield in Dagang, Hebei Province, China (the "Dagang Project"). Under the contract we operate the project and fund 100% of the development costs to earn 82% of the net revenue from oil production until cost recovery, at which time our entitlement reduces to 49%.

We have a marketing arrangement with CNPC whereby we have the option of either exporting our share of oil production or selling it to them. We are currently selling our crude oil to CNPC at a three month

rolling average price of Cinta crude oil as published by Platts. The average price of Cinta crude oil over the last three years is approximately \$2.00 per barrel less than the West Texas Intermediate ("WTI") price. All sales are settled in United States dollars.

We are obliged to pay value added tax of 5% on oil production from the Dagang Project. We pay no royalty until annual gross production of crude oil from a particular block within the Dagang Project exceeds 500,000 tonnes per annum. Royalties then become payable at a rate of 2% and increase incrementally as the rate of production increases to a maximum of 12.5% once annual gross production on a block exceeds four million tonnes. We do not expect that any of the blocks will produce more than 500,000 tonnes per annum and as such no royalty payments are anticipated. Our entire interest in the Dagang Project will revert to CNPC at the end of the 20-year production period or if we abandon the project earlier.

In 1999 we farmed out a 20% working interest in the Dagang project to Nippon Oil Exploration Limited ("Nippon") for which Nippon agreed to fund \$6 million of pilot testing expenditures. At the end of the pilot phase, Nippon elected to relinquish its 20% working interest back to us.

During 2001, we completed the pilot testing phase and submitted an overall development plan to Chinese regulatory authorities for approval. We expect to receive this approval during the first half of 2002. The development phase of the Dagang project will commence once all necessary approvals and financing have been received. The development phase will cost approximately \$185 million over a three-year period and will involve drilling 115 new wells and reworking approximately 29 of the 82 existing wells.

Daqing Project

Until January 2002 we were party to another production sharing contract with CNPC which covers an area of 8,100 gross acres in the Zhaozhou oilfield in Daqing, Heilongjiang Province, China (the "Daqing Project"). The Daqing Project, which is relatively small, was initially undertaken by us on the expectation that we would be able to acquire rights to additional land blocks. Our negotiations were unsuccessful to acquire the additional blocks necessary to provide critical mass. We decided to divest of our interest in the Daqing Project and in January 2002, we sold our interest in the Daqing Project for \$2.4 million and a right to an overriding royalty on future production.

Sichuan Basin

In February 2001, we signed two memoranda of understanding with PetroChina. These memoranda give us the exclusive right to negotiate petroleum contracts for three land blocks in Sichuan province. We have agreed with PetroChina to carry out joint feasibility studies on the Zitongxi, Zitongdong and Yudong blocks. These blocks, located in the Sichuan Basin, approximately 930 miles southwest of Beijing cover an area of approximately 2.2 million acres. If the results of the joint feasibility studies are positive, we will proceed to negotiate production sharing contracts, and seek Chinese regulatory approval. PetroChina has drilled 39 wells on the three blocks. Twenty-six of these wells have been classified as producing gas wells. PetroChina has production tested 8 of the estimated 38 hydrocarbon bearing structures located on the three blocks. We are still in the process of assessing the resources and formulating a potential development plan.

COMPETITION

The oil and gas industry is highly competitive. Our position in the oil and gas industry, which includes the search for, and development of, new sources of supply, is particularly competitive. The oil and gas industry also competes with other industries in supplying energy, fuel and other needs of consumers. See "Risk Factors."

ENVIRONMENTAL REGULATIONS

Both our oil and gas and GTL operations are subject to various levels of government laws and regulations relating to the protection of the environment in the countries in which they operate. We believe that our operations comply in all material respects with applicable environmental laws.

In the United States, environmental laws and regulations, implemented principally by the Environmental Protection Agency, Department of Transportation and the Department of the Interior and comparable state agencies, govern the management of hazardous waste, the discharge of pollutants into the air and into surface and underground waters and the construction of new discharge sources, the manufacture, sale and disposal of chemical substances, and surface and underground mining. These laws and regulations generally provide for civil and criminal penalties and fines, as well as injunctive and remedial relief.

In China, environmental regulation does not exist on a national level. Individual projects are monitored by the state and the standard of environmental regulation depends on each case.

GOVERNMENT REGULATIONS

Our business is subject to certain United States and Chinese federal, state and local laws and regulations relating to the exploration for, and development, production and marketing of, crude oil and natural gas, as well as environmental and safety matters. In addition, the Chinese government regulates various aspects of foreign company operations in China. Such laws and regulations have generally become more stringent in recent years in the United States, often imposing greater liability on a larger number of potentially responsible parties. It is not unreasonable to expect that the same trend will be encountered in China. Because the requirements imposed by such laws and regulations are frequently changed, we are not able to predict the ultimate cost of compliance.

EMPLOYEES

At March 1, 2002, we had 69 employees. None of our employees are unionized.

RESERVES, PRODUCTION AND RELATED INFORMATION

See the Supplementary Disclosures About Oil and Gas Production Activities included under Item 8 in this Annual Report for information with respect to our oil and gas producing activities. We have not filed with or included in reports to any other United States federal authority or agency, any estimates of total proved crude oil or natural gas reserves since the beginning of the last fiscal year.

The following tables set forth, for each of the last three fiscal years, our average sales prices and average production costs per unit of production. Average sales prices are after royalties in the United States, China and Russia. In China for 1999 and 2000, proceeds from the sale of oil produced were credited to our China cost pool due to the stage of development of our projects in China. In 2000, the average sales price realized on China production was \$28.26 (1999 — \$21.27). Average production costs include lifting costs and production taxes, but exclude allocated head office engineering support costs, depreciation, depletion and amortization, royalties, income taxes, interest and selling administrative and other expenses.

	Average Sales Price			Average Production Cost		
	2001	2000	1999	2001	2000	1999
Crude Oil and Natural Gas Liquids (\$/Boe)						
United States	\$21.93	\$27.52	—	\$ 8.29	\$10.00	—
China	\$24.42	—	—	\$10.50	—	—
Russia	—	—	\$4.68	—	—	\$2.49

The following tables set forth the number of productive wells (both producing wells and wells capable of production) in which we held a working interest at December 31, 2001 and 2000:

	2001 Oil		2000 Oil	
	Gross(1)	Net(2)	Gross(1)	Net(2)
United States	59	48.4	29	25.6
China	13	10.8	9	6.7

(1) Gross wells are the total number of wells in which an interest is owned.

(2) Net wells are the sum of fractional interests owned in gross wells.

The following table sets forth, for each of the last three fiscal years, our participation in the completed drilling of net crude oil and natural gas wells:

Exploratory

	Productive		
	2001	2000	1999
United States	—	—	—
China	—	—	—
Total	<u>0</u>	<u>0</u>	<u>0</u>

	Dry		
	2001	2000	1999
United States	1.5	2.5	2
China	—	—	—
Total	<u>1.5</u>	<u>2.5</u>	<u>2</u>

Development

	Productive		
	2001	2000	1999
United States	22.8	25.6	—
China	—	3.3	3.4
Total	<u>22.8</u>	<u>28.9</u>	<u>3.4</u>

	Dry		
	2001	2000	1999
United States	—	2	—
China	—	—	—
Total	<u>0</u>	<u>2</u>	<u>0</u>

The following tables set forth our holdings of developed and undeveloped oil and gas acreage at March 1, 2002:

	Developed		Undeveloped	
	Gross Acres(1)	Net Acres(2)	Gross Acres(1)	Net Acres(2)
United States	2,465	1,794	149,533	89,853
China(3)	1,976	1,367	28,479	19,707

- (1) Gross acres include the interests of others.
- (2) Net acres exclude the interests of others.
- (3) The number of developed acres disclosed in respect of our China projects relates only to those portions of the relevant fields covered by our pilot testing operations and does not include the remaining portions of the fields previously developed by CNPC.

The following table sets out estimates of our share of proved reserves in respect of our United States and China operations and calculations of cash flows, before tax and after tax, undiscounted and discounted at 10% and 15%, based on costs and prices as at December 31, 2001. Estimates for our China operations were prepared by independent petroleum consultants Gilbert Laustsen Jung Associates Ltd.. Independent petroleum consultants Allan Spivack Engineering and Joe C. Neal & Associates prepared estimates for our United States operations.

	Our Share		Our Share of Before Tax Cash Flows in thousands of dollars discounted at:			Our Share of After Tax Cash Flows in thousands of dollars discounted at:		
	OIL (MBbl)	GAS (MMcf)	0%	10%	15%	0%	10%	15%
Proved Reserves(1)								
United States	2,003	1,631	\$ 17,060	\$ 10,243	\$ 8,379	\$ 17,060	\$ 10,243	\$ 8,379
China(2)	21,795	—	59,600	10,331	—	54,074	8,046	—
	<u>23,798</u>	<u>1,631</u>	<u>\$ 76,660</u>	<u>\$ 20,574</u>	<u>\$ 8,379</u>	<u>\$ 71,134</u>	<u>\$ 18,289</u>	<u>\$ 8,379</u>

- (1) "Proved Reserves" are the estimated quantities of crude oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic conditions. Our share of the reserves is shown before royalties. Our share of the reserves net of royalties is disclosed in the "Supplementary Disclosures about Oil and Gas Production Activities", which follow the notes to our financial statements set forth in Item 8 of this Annual Report.
- (2) In late January 2002 we disposed of our interest in our Daqing project. For purposes of this schedule the reserves for Daqing of 3,449 MBbl represent the reserve volumes reported by Gilbert Lausten Jung Associates Ltd. as at December 31, 2000 less 2001 production. The undiscounted value attributed to the Daqing reserves of \$5,185,000 before and after tax (\$3,897,000 before and after tax discounted at 10%), represents the value of consideration received on disposal.

ITEM 3. LEGAL PROCEEDINGS

We are not currently a party to any material legal proceedings.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Market Information

Our common shares are traded on the NASDAQ National Market and The Toronto Stock Exchange.

The high and low sale prices of our common shares as reported on the NASDAQ National Market and the Toronto Stock Exchange for each quarter during the past two years are as follows:

NASDAQ NATIONAL MARKET (IVAN)

	2001				2000			
	1st Q	2nd Q	3rd Q	4th Q	1st Q	2nd Q	3rd Q(1)	4th Q
High	5.1875	4.98	3.83	2.51	—	—	4.6875	6.75
Low	3.25	3.18	1.39	1.40	—	—	4.00	3.875

(1) Our common shares did not commence trading on the NASDAQ National Market until August 28, 2000.

THE TORONTO STOCK EXCHANGE (IE) (CDN.\$)

	2001				2000			
	1st Q	2nd Q	3rd Q	4th Q	1st Q	2nd Q	3rd Q	4th Q
High	7.65	7.40	5.80	3.99	4.20	7.20	7.50	9.80
Low	5.15	4.90	2.15	2.20	2.50	2.61	5.95	6.00

On March 1, 2002, the closing prices for our common shares were \$2.00 on the NASDAQ National Market and Cdn. \$3.10 on The Toronto Stock Exchange.

Holders of Common Shares

As at March 1, 2002, a total of 139,517,708 of our common shares were issued and outstanding and held by 114 holders of record.

Dividends

We have not paid any dividends on our outstanding common shares since we were incorporated and we do not anticipate that we will do so in the foreseeable future. The declaration of dividends on our common shares is, subject to certain statutory restrictions described below, within the discretion of our Board of Directors based on their assessment of, among other factors, our earnings or lack thereof, our capital and operating expenditure requirements and our overall financial condition. Under the *Yukon Business Corporations Act*, our Board of Directors has no discretion to declare or pay a dividend on our common shares if they have reasonable grounds for believing that we are, or would after payment of the dividend be, unable to pay our liabilities as they become due or that the realizable value of our assets would, as a result of the dividend, be less than the aggregate sum of our liabilities and the stated capital of our common shares.

Exchange Controls and Taxation

There is no law or governmental decree or regulation in Canada that restricts the export or import of capital, or affects the remittance of dividends, interest or other payments to a non-resident holder of our common shares, other than withholding tax requirements.

There is no limitation imposed by the laws of Canada, the laws of the Yukon, or our constating documents on the right of a non-resident to hold or vote our common shares, other than as provided in the *Investment Canada Act* (Canada) (the "Investment Act"), which generally prohibits a reviewable investment by an entity that is not a "Canadian", as defined, unless after review, the minister responsible for the Investment Act is satisfied that the investment is likely to be of net benefit to Canada. An investment in our common shares by a non-Canadian who is not a "WTO investor" (which includes governments of, or individuals who are nationals of, member states of the World Trade Organization and corporations and other entities which are controlled by them), at a time when we were not already controlled by a WTO investor, would be reviewable under the Investment Act under two circumstances. First, if it was an investment to acquire control (within the meaning of the Investment Act) and the value

of our assets, as determined under Investment Act regulations, was Cdn.\$5,000,000 or more. Second, the investment would also be reviewable if an order for review was made by the federal cabinet of the Canadian government on the grounds that the investment related to Canada's cultural heritage or national identity (as prescribed under the Investment Act), regardless of asset value. An investment in our common shares by a WTO investor, or by a non-Canadian at a time when we were already controlled by a WTO investor, would be reviewable under the Investment Act if it was an investment to acquire control and the value of our assets, as determined under Investment Act regulations, was not less than a specified amount, which for 2002 is Cdn.\$218 million. The Investment Act provides detailed rules to determine if there has been an acquisition of control. For example, a non-Canadian would acquire control of us for the purposes of the Investment Act if the non-Canadian acquired a majority of our outstanding common shares. The acquisition of less than a majority, but one-third or more, of our common shares would be presumed to be an acquisition of control of us unless it could be established that, on the acquisition, we were not controlled in fact by the acquirer. An acquisition of control for the purposes of the Investment Act could also occur as a result of the acquisition by a non-Canadian of all or substantially all of our assets.

Amounts that we may, in the future, pay or credit, or be deemed to have paid or credited, to you as dividends in respect of the common shares you hold at a time when you are not a resident of Canada within the meaning of the *Income Tax Act* (Canada) will generally be subject to Canadian non-resident withholding tax of 25% of the amount paid or credited, which may be reduced under the Canada-United States Income Tax Convention (1980) (the "Convention"). Currently, under the Convention, the rate of Canadian non-resident withholding tax on the gross amount of dividends paid or credited to a U.S. resident is generally 15%. However, if the beneficial owner of such dividends is a U.S. resident corporation which owns 10% or more of our voting stock, the withholding rate is reduced to 5%. In the case of certain tax exempt entities which are residents of the United States for the purpose of the Convention, the withholding tax on dividends may be reduced to 0%.

Sales of Unregistered Securities

During the year ended December 31, 2001, we issued securities which were not registered under the Securities Act of 1933 (the "Act") as follows:

- in May 2001, we issued 800,000 common shares to two of our existing shareholders in exchange for all of the issued and outstanding shares of Digital Petrophysics Resources, Inc., a company holding overriding royalty interests in certain of our California exploration properties, in a transaction exempt from registration under Section 4(2) of the Act; and
- in October 2001, we issued 10,885,000 special warrants at a price of \$1.60 per special warrant to a number of Canadian individual and institutional investors in a transaction exempt from registration under Rule 903 of the Act and 375,000 special warrants at a price of \$1.60 per special warrant to two accredited investors in a transaction exempt from registration under Rule 506 of the Act. Each special warrant was exercisable to acquire, for no additional consideration, one common share following the issuance of a receipt for a prospectus by applicable Canadian provincial securities regulatory authorities, which occurred in November 2001.

ITEM 6. SELECTED FINANCIAL DATA

The selected financial data set forth below are derived from the accompanying financial statements, which form part of this Annual Report. The financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") applicable in Canada, which is not materially different from GAAP in the United States, except in 2001 for which an additional impairment provision for the carrying value of our China properties of \$10 million and the need to write-off development costs of \$5.1 million in connection with our GTL prospects are required under United States GAAP. For a United States GAAP reconciliation, see Note 15 to our financial statements. See also Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operation".

The following table shows selected financial information for the periods indicated:

	Year ended December 31,				
	2001	2000	1999	1998	1997
(stated in thousands of U.S. dollars, except per share amounts)					
Revenues	\$ 9,722	\$14,063	\$ 6,210	\$ 12,752	\$ 15,077
Total assets	104,003	99,800	47,659	49,442	120,483
Long-term debt	Nil	Nil	Nil	1,763	1,718
Net earnings (loss)	(21,122)(1)	5,429	(7,802)(2)	(70,677)(3)	(2,185)
Net earnings (loss) per share — basic	(0.16)	0.05	(0.08)	(0.79)	(0.03)
Net earnings (loss) per share — diluted	(0.16)	0.04	(0.08)	(0.79)	(0.03)

- (1) Includes asset write down of \$14.0 million. For United States GAAP purposes an additional asset write down of \$15.1 million is required. See Note 15 to our financial statements under Item 8 in this Annual Report.
- (2) Includes asset write down of \$2.5 million. See Note 8 to our financial statements under Item 8 in this Annual Report.
- (3) Includes asset write down \$70.2 million. See Note 9 to our financial statements under Item 8 in our 2000 Annual Report

Reconciliation to GAAP in United States

Our financial statements have been prepared in accordance with GAAP applicable in Canada, which differ in certain respects from those principles that we would have followed had our financial statements been prepared in accordance with GAAP in the United States. The only material differences between Canadian and United States GAAP which affect our financial statements is that under United States GAAP an additional impairment provision of \$10 million and a write-off of \$5.1 million in connection with development costs for our GTL prospects are required in 2001. Determination of earnings per share in 1998, 1999 and 2000 is calculated excluding shares held in escrow.

If we followed U.S. GAAP, certain selected financial information reported above would have been reported as follows. Potential exercise of the stock options and warrants disclosed in Note 5 to the financial statements and potential conversion of the debt, Note 4, do not have a material dilutive effect on the earnings per share.

	Year ended December 31,				
	2001	2000	1999	1998	1997
(stated in thousands of U.S. dollars, except per share amounts)					
Net earnings (loss)	\$ (36,264)	\$ 5,429	\$ (7,802)	\$ (70,677)	\$ (2,185)
Net earnings (loss) per share — basic	(0.28)	0.05	(0.09)	(1.10)	(0.04)
Net earnings (loss) per share — diluted	(0.28)	0.04	(0.09)	(1.10)	(0.04)

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Critical Accounting Principles and Estimates

Our accounting principles are described in Note 2 to Notes to the Consolidated Financial Statements in Item 8. We prepare our Consolidated Financial Statements in conformity with GAAP in Canada, which conform in all material respects to United States GAAP except for those items disclosed in Note 2 to Notes to the Consolidated Financial Statements. For United States readers we have detailed the differences and have also provided a reconciliation of the differences between United States and Canadian GAAP in Note 15 to Notes to the Consolidated Financial Statements.

The preparation of our financial statements requires us to make estimates and judgements that affect our reported amounts of assets, liabilities, revenue and expenses. On an ongoing basis we evaluate our estimates, including those related to asset impairment, revenue recognition, allowance for doubtful accounts and contingencies and litigation. These estimates are based on information that is currently available to us and on various other assumptions that we believe to be reasonable under the circumstances. Actual results could vary from those estimates under different assumptions and conditions.

We have identified the following critical accounting policies that affect the more significant judgements and estimates used in preparation of our consolidated financial statements.

Full Cost Accounting — We follow the full cost method of accounting for our oil and gas operations (as more fully described in Note 2 to the Consolidated Financial Statements), as compared to the other generally accepted method, successful efforts. Under the full cost method, costs associated with drilling successful and unsuccessful wells are capitalized on a country-by-country basis. As a consequence we may be more exposed to potential impairments if the book value of capitalized costs exceeds their future expected cash flows. This may occur if recoverable reserve estimates decrease, commodity prices decline or future estimates for capital, operating and income taxes increase, to levels that would significantly affect anticipated future cash flows.

Oil and Gas Reserves — The process of estimating quantities of proved reserves is inherently uncertain and the reserve estimates included in this document are only estimates (see "Risk Factors"). You should not assume that the present value of our future cash flows is the current market value of our estimated proved oil and gas reserves. In accordance with GAAP we base the estimated future net cash flows from proved reserves on prices and costs on the date of estimate. Actual future prices and costs may be materially higher or lower than the prices and costs at the date of estimate.

Depletion — Our rate of recording depletion is dependent upon our estimate of proved reserves. If the estimates of proved reserves decline, the rate at which we record our depletion expense increases, reducing net income. Such a decline in proved reserves may occur from lower product prices, which may make it non-economic to drill for and produce higher cost fields.

Year Ended December 31, 2001

Overview

Our 2001 plan was to advance our short, medium and long-term objectives towards our overall goal of creating a diversified global energy company focused on three growth strategies: conventional E&P, EOR projects on a production-sharing basis with national petroleum companies, and production of cleaner burning fuels from natural gas using proven GTL technology.

Our short-term objective to secure cash flow was advanced through our activities at our South Midway Sunset in California and Spraberry in west Texas as well as the submission of our development plan in our EOR project at Dagang in China. Our 2001 U.S. production increased almost 8 fold over 2000 to 232,600 Boe. Net revenues from our U.S. projects increased to \$5.1 million from \$851,000 the previous year. Our 2001 China pilot production increased 61% to 165,600 barrels of oil with net revenue increasing \$1.1 million to \$4 million. Our operating results however, suffered from the decline in oil and gas prices in the second half of 2001. In the U.S. these declines necessitated a provision for impairment of capitalized costs of \$14 million and reduced our net revenue to \$1.1 million in the fourth quarter compared to \$1.5 million in the previous quarter. In China the fourth quarter decline in net revenue was less dramatic due to the impact of three month averaging of our oil prices. However, on application of U.S. GAAP at year-end an impairment provision of \$10 million on the carrying value of our China properties was necessary.

Our medium-term objective to explore for deep gas in the San Joaquin Basin in California and the Bossier gas sands in east Texas was advanced with the spud of our Northwest Lost Hills 1-22 well in California in August, and the commencement of drilling of our initial 2 wells at Bossier. In China we

identified an opportunity to participate in a major natural gas opportunity in the Sichuan Basin and secured the exclusive right to negotiate production-sharing contracts with PetroChina in 3 blocks.

We continue to advance our long-term strategy to become a leader in the development of GTL projects through negotiations, currently underway, in Qatar and Egypt to secure the rights to exploit stranded natural gas reserves through the use of GTL technology. We have also undertaken a number of technical and marketing studies to assist in evaluating the economic viability of the prospects.

Operations

Our net loss for the year was \$21.1 million (\$0.16 per share) compared to net income in 2000 of \$5.4 million (\$0.05 per share). The net change year over year of \$26.5 million is attributable to a \$14.0 million write down of our United States properties under the ceiling test calculation in 2001 and the \$12.2 million gain on the sale of our Russian properties recorded in 2000. As more fully explained in Note 15 to our consolidated financial statements, included in Item 8 herein, on application of United States GAAP an additional \$10 million write down of our China property and a \$5.1 million write-off of capitalized development costs in connection with our GTL prospects are required. No similar write-downs are required under Canadian GAAP. Our cash flow from operating activities for the year ended December 31, 2001 was \$2.4 million, up from the cash flow deficiency from operating activities of \$11.8 million we experienced in 2000. In 2001, we raised \$18.2 million through private placements and the exercise of warrants and incentive stock options (\$47.7 million was raised in 2000 from similar sources). In 2001 we invested \$40.5 million (\$40.8 million in 2000), primarily in exploration and development activities.

Production

At our South Midway Sunset field in California we have drilled 31 wells, 29 of which are producing. We are currently producing approximately 400 net Bbls/d. In the fourth quarter of 2001 we completed a pilot cyclic steam enhancement project, which was very successful in more than doubling production rates in the five wells that were treated. A full-scale cyclic steam project is now being planned to commence in 2002. South Midway Sunset is primarily designed to provide us with immediate cash flow from a low risk, low cost development project with existing infrastructure. We own a 100% working interest and a 93% net revenue interest in the project. Aera elected not to participate in this project but receives royalties pursuant to the Aera exploration agreement.

As of the end of 2001 we have drilled 30 wells in the Spraberry field, which are producing approximately 300 net Boe/d. All 30 wells have been completed in one or more of the Wolfcamp zones but 5 wells still are awaiting their Spraberry zone completions. We plan to start these completions in early 2002 and finish them by the end of 2002. During the remainder of 2002, we may drill an additional six to eight wells in the area known as Apache Flats where we have a 40% working interest before payout. To date we have drilled three wells in this area that are producing 40 net Boe/d.

South Midway Sunset and Spraberry are our only producing fields in the United States. The substantial declines in oil and gas product prices during 2001 have had significant impact on our operating profitability at these fields and have made it necessary to provide a provision for impairment on the carrying value of our United States evaluated oil and gas assets. We recorded an impairment provision of \$5 million at the end of the second quarter and an additional provision of \$9 million at the end of the third quarter. No further provision was required at year-end.

In China, with the decision on both our projects to proceed to the development stage, we commenced in early 2001 to record our production from our pilot wells as income as opposed to crediting project carrying costs as was previously our practice. At year end, 8 wells were producing at Dagang at a rate of 555 Bbls/d and 2 wells at Daqing producing at 51 Bbls/d.

Production and revenues we generated in 2001 are detailed below. Although we generated production revenue in 1999, it was all attributable to our former Russian operations and, as a consequence, is not comparable.

	2001		
	U.S.	China	Total
Net Production			
Oil — Bbls	211,366	165,599	376,965
Gas — Mcf	127,306	—	127,306
Boe	232,584	165,599	398,183
Per Boe			
Average sales price	\$ 21.93	\$ 24.42	\$ 22.96
Operating costs	7.28	10.50	8.62
Production taxes	1.01	0.00	0.59
	8.29	10.50	9.21
Depletion, Depreciation and Amortization	8.12	6.79	7.56
	16.41	17.29	16.77
Net	\$ 5.52	\$ 7.13	\$ 6.19

Total revenue from our oil and gas operations was \$9.1 million. Operating costs we reported in our statement of income (loss) included allocated head office engineering support of \$1.1 million for 2001 (2000 — \$0.5 million).

Project Identification Costs

We remain committed to the geographical diversification of our oil and gas activities. We follow the practice of expensing the costs we incur in pursuing and investigating new projects as well as costs associated with investment banking advice. During 2001, we incurred \$6.2 million, up \$2.5 million from the \$3.7 million incurred in 2000, in costs associated with international project opportunities that we have rejected. Of the increase \$1.4 million is attributable to payments to investment bankers for assistance with financial and strategic planning.

General and Administration

We incurred general and administrative costs of \$2.6 million during 2001, down \$0.3 million from the \$2.9 million we incurred in 2000.

Other Income and Expenses

Interest income represents income we earned on our excess cash balances held during the year. The decrease of approximately \$0.4 million from 2000 arises from a reduction of our cash balances and interest rates during 2001. Russian litigation costs ceased in mid 2000 with the successful resolution of our dispute with our Russian joint venture partner and divestiture of our Russian projects. Depletion and depreciation is up \$2.9 million from 2000 due to the inclusion of production from our US properties for a full year and the inclusion of production from China in income in 2001.

Income Taxes

We have significant tax losses available to carry forward and reduce taxes otherwise payable. Details of these losses are in Note 10 to the consolidated financial statements included herein under Item 8. Given the uncertainty as to the utilization of these tax loss carry-forwards, we have followed the practice of recording a provision against the tax benefit asset resulting from these losses.

Exploration and Development Activities

During 2001 we continued our exploration program in the San Joaquin Valley of Southern California on acreage primarily acquired under the Aera exploration agreement. Using the extensive proprietary

seismic and technical databases owned by Aera and supplemented by us, we have identified over 40 drillable prospects in 18 Areas of Mutual Interest ("AMIs") covering approximately 72,800 acres. Aera has elected to participate in 12 of these AMIs (in which we have working interest ranging from 12.5% to 50%); in 3 AMIs Aera elected not to participate and on 2 AMIs Aera has yet to make an election. In the remaining AMI we have both elected not to pursue the prospect and have farmed it out retaining an overriding royalty interest. We spud our first deep gas exploration well at Northwest Lost Hills in Kern County, results of which will not be known until the second quarter 2002. In addition, we drilled 2 other exploration wells in southern California, which were unsuccessful, and were abandoned. See Items 1 and 2. "Description of Business and Properties — Oil and Gas Properties — California — Aera Exploration Agreement". At South Midway Sunset we continued our drilling program by drilling 10 more development wells, all commercial oil producers. (See above discussion under "Production") Additionally we initiated a pilot cyclic steam enhancement project, resulting in a full-scale steam project planned to commence in 2002. We acquired overriding royalties, ranging from 1.75% to 6.58%, in the deep rights of certain leases of the Aera exploration agreement.

In Texas, we drilled an additional 14 producing wells in the Spraberry Trend acreage in west Texas. (see above discussion under "Production") In 2001, we spud 2 wells in the Cresslan Ranch prospect within the Bossier Trend in east Texas, both of which encountered gas shows and are currently being prepared for stimulation and testing. We continue to increase our leased acreage in the Bossier area.

In Kentucky, through a participation agreement entered into in March 2001, we drilled 3 exploration wells. Two are currently awaiting stimulation before testing and one well is suspended.

At our Dagang Project in China, we completed our pilot-testing phase in February 2001 and later in the year submitted our overall development plan to the Chinese authorities for their approval, which is expected in the first half of 2002. In the interim, we continue to operate the pilot wells with production revenue accruing to us. At our Daqing Project, our overall development plan was approved in February 2001 and we resumed operatorship and rights to revenues March 1 2001. The resumption of our rights to revenues at Daqing represents the primary difference between our China oil production reported below of 102,708 net barrels and the China oil production of 165,599 in 2001. Our Daqing Project is small by international standards and negotiations with CNPC for additional blocks to be included in the contract area have proved unsuccessful and after an internal review our China projects, and based on our shift towards major gas development in China we put the Daqing project up for disposal. Effective January 22, 2002 we disposed of the project for \$2.4 million and an overriding royalty on future production.

With the decision to proceed to the development stage, beginning in 2001 for accounting purposes, all oil revenues and related operating costs are included in our statement of loss and deficit. For Daqing this was March 1, 2001. The following summarizes the production and revenue we realized from the pilot testing phase of our Dagang Project during 2000 and 1999. Prior to deciding to proceed to the development phase, this revenue was credited to the China cost pool for accounting purposes. During this same period under a special arrangement with CNPC we had relinquished our operations of the Daqing project and therefore we show no pilot test production for that time frame. All sales of oil are at or about WTI less approximately \$2.00 for quality and transportation. We receive all proceeds in U.S. dollars offshore China.

	2000	1999
Oil production (net) — Bbls	102,708	4,334
Price per Bbl realized	\$ 28.26	\$ 21.27
Total proceeds	\$2,903,000	\$92,203

Total capital spending on oil and gas operations, including non-cash transactions, during 2001 compared to 2000 was as follows:

	2001 (in thousands)	2000
Capital Expenditures:		
United States	\$33,865	\$22,816
China	<u>6,502</u>	<u>5,676</u>
	<u>\$40,367</u>	<u>\$28,492</u>
Comprised of:		
Property acquisition.....	\$ 5,688	\$ 6,392
Royalty acquisition	4,043	1,157
Seismic	1,348	3,840
Exploration	10,197	667
Development	<u>19,091</u>	<u>19,376</u>
	<u>40,367</u>	<u>31,432</u>
Less: China oil production	<u>—</u>	<u>(2,940)</u>
	<u>\$40,367</u>	<u>\$28,492</u>

Gas-to-Liquids

In 2000, we acquired a master license from Syntroleum permitting us to use Syntroleum's proprietary GTL process in an unlimited number of GTL projects around the world except North America, China and India. We have identified and are aggressively pursuing projects in Qatar and Egypt. To date we have undertaken detailed feasibility studies for the construction, operation and cost of GTL plants and conducted marketing and transportation feasibility studies for Europe and the Asia-Pacific regions. Costs of \$5.1 million (\$3.9 million incurred in 2001) incurred in connection with the ongoing negotiations for these projects and the costs of our feasibility studies have been capitalized. For United States GAAP purposes these costs have been written off. See Items 1 and 2. "Description of Business and Properties — Gas-to-Liquids Projects".

In 2000, we invested \$2 million in Syntroleum's Sweetwater project to be located on the Burrup Peninsula in Western Australia. An additional \$19 million investment was agreed, contingent on Syntroleum securing project financing. We have since identified two larger GTL project opportunities in Qatar and Egypt, which may affect our continuing participation in Sweetwater. However, no decision has been reached at this time.

Liquidity and Capital Resources

In 2001 we commenced an aggressive capital expenditure program. For the year ended December 31, 2001 we expended \$ 36.8 million for acquisition, exploration and development activities and an additional \$3.9 million to further our GTL business. To facilitate these expenditures we raised \$18 million through private placement.

In 2002 we plan to incur capital expenditures of approximately \$45 million of which \$25 million is allocated to our exploration and development activities and an additional \$20 million is allocated to furthering our GTL activities. Actual exploration and development expenditures in California and Texas will be contingent upon continued drilling success at Northwest Lost Hills and Bossier. Actual GTL expenditures will be primarily contingent upon the successful outcome of our negotiations in Qatar and our future role, if any, in the Sweetwater project.

At current oil and gas prices and given our cash on hand at year end no additional funding will be required to fund our current level of administrative and engineering costs through 2002. Our \$1 million convertible debenture is due in August 2002, if the holders choose not to convert.

We currently do not have the financial resources to carry out our planned 2002 capital expenditures. It will be necessary for us to raise the funds through the issuance of equity or debt securities, project financing, additional joint ventures with third parties, disposal of non-core asset or a combination of the foregoing. While we have had success in the past in raising funds through the issue of equity, we can give no assurance that we will be able to in the future. Should we be unable to raise the necessary funds to carry out our 2002 budget it will be necessary to prioritize our activities, which may result in our delaying and potentially losing some valuable business opportunities. Any such delay or loss may have a material adverse effect on our ability to successfully implement our corporate strategy.

Subsequent to year-end we raised \$2.4 million from disposal of our Daqing project in China.

Off Balance Sheet Disclaimer:

At December 31, 2001 and 2000, we did not have any relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. In addition, we do not engage in trading activities involving non-exchange traded contracts. As such, we are not materially exposed to any financing, liquidity, market or credit risk that could arise if we had engaged in such relationships. We do not have relationships and transactions with persons or entities that derive benefits from their non-independent relationship with us or our related parties except as disclosed herein.

Year Ended December 31, 2000

Overview

During 2000, we concentrated our efforts on developing drillable prospects in the San Joaquin Valley of California on acreage covered by the Aera exploration agreement and on additional acreage we acquired there. To date, we have identified six drillable prospects. We have selected a location for our first deep-gas well at Northwest Lost Hills and, depending on rig availability, we plan to spud the well during the second quarter of 2001. During the second quarter of 2000, we commenced a drilling program in the South Midway Sunset area and, by year-end, we had drilled 21 wells. We commenced commercial production during the third quarter.

In 2000, we secured a 62.5% interest (96% interest in the first four wells) in 9,100 gross (5,700 net) acres in the Spraberry Trend of the West Texas Permian Basin. By year-end, we had spudded 16 wells. Our interest in the play decreases to 50% after payout. During the fourth quarter of 2000 and the first two months of 2001, we acquired an interest in over 28,400 gross (20,700 net) acres in the Bossier sands in East Texas, where we expect to commence drilling in the third quarter of 2001.

At our two projects in China, we concentrated our efforts on completing the pilot testing phase of the Dagang Project and obtaining approval by the Chinese government for our overall development plan at our Daqing Project, which we received in February, 2001. Implementation of the plan is scheduled to commence in the third quarter of 2001. At our Dagang Project, the pilot testing phase was completed successfully in February 2001. We now plan to proceed with the development phase which will require the submission of an overall development plan to the Chinese government for approval. We expect to submit it in the second half of 2001.

During 2000, we acquired a master license from Syntroleum permitting us to use Syntroleum's proprietary GTL technology and on October 5, 2000 we signed a letter of intent with Syntroleum to acquire a 13% non-recourse partnership interest in Syntroleum's Sweetwater GTL project under development in Western Australia.

In August, 2000 we were successful in negotiating a settlement of our legal dispute with our Russian partner at Tura in Western Siberia. In consideration for relinquishing our entire interest in Tura and the adjacent Radonezh Project, we received \$28.2 million, net of settlement and severance costs of \$0.8 million.

Operations

Our net income for the year was \$5.4 million (\$0.05 per share) compared to a loss in 1999 of \$7.8 million (\$0.08 per share). We attribute the improvement from 1999 to the commencement of initial production from our properties in California and Texas and from the gain of \$12.2 million we realized from the settlement of our Russian dispute. Our cash flow deficiency from operating activities for the year ended December 31, 2000 was \$11.8 million, up 90% from the cash flow deficiency from operating activities of \$6.2 million we experienced in 1999. In 2000, we raised \$47.7 million through private placements and exercise of warrants and incentive stock options (\$0.7 million in 1999) and invested \$40.8 million (\$10.7 million in 1999) in capital assets. By the end of 2000, we were able to sell, without further loss, the last of our equipment originally destined for Russia.

Production

In 2000, we commenced production at our South Midway Sunset field in California and at our Spraberry field in West Texas. At South Midway Sunset we drilled and completed our first well and went into production in July 2000. By year-end we had drilled a total of 21 wells of which 19 were completed and 17 in production. The remaining two completed wells were placed on production in January 2001. The two uncompleted development wells were dry, one of which we plan to use as a water disposal well. At the Spraberry Trend, we drilled 16 wells in 2000, of which 10 were completed and on production by year-end, with the remaining six wells completed and placed on production in early 2001. To date in 2001, we have drilled an additional six development wells, of which one was placed on production in February, 2001.

Production and revenues we generated in 2000 are detailed below. Although we generated production revenue in 1999 and 1998, it was all attributable to our former Russian operations and, as a consequence, is not comparable.

	2000		
	Midway	Spraberry	Total
Net Production			
Oil — Bbls	19,096	10,981	30,077
Gas — Mcf	—	4,816	4,816
Boe	19,096	11,833	30,929
Per Boe			
Average sales price	\$ 25.39	\$ 30.96	\$ 27.52
Operating costs	13.56	4.25	10.00
Production taxes	—	1.50	0.57
	13.56	5.75	10.57
Depletion, Depreciation and Amortization			8.70
			19.27
Net			\$ 8.25

Total revenue from our oil and gas operations was \$851,000. Our operating costs at South Midway Sunset were unusually high due to facility rental costs associated with start-up operations. We expect to reduce our operating costs at South Midway Sunset to the \$4.00 per barrel range during the second quarter of 2001. Operating costs we reported in our statement of income include allocated head office engineering support costs of \$0.5 million. Depletion, depreciation and amortization costs are high due to the nature of the South Midway Sunset and Spraberry Trend projects. While South Midway Sunset and Spraberry Trend require high development and facility costs to exploit limited reserves, both provide good economic returns at current oil and natural gas prices.

Project Identification Costs

We remain committed to the geographical diversification of our oil and gas activities. We follow the practice of expensing the costs we incur in pursuing and investigating new projects. With the acquisition of our Syntroleum master license, we have intensified our search for new international oil and gas and GTL projects. During 2000, we incurred \$3.7 million, up \$2.0 million from the \$1.7 million incurred in 1999, in costs associated with international project opportunities that we have rejected or that we were still investigating at year-end. Once we obtain rights or interests in a new project we capitalize the costs we incurred in obtaining the project.

General and Administration

We incurred general and administrative costs of \$2.8 million during 2000, up \$0.2 million from the \$2.6 million we incurred in 1999. We attribute the bulk of the increase to the costs associated with listing on NASDAQ in 2000.

Other Income and Expenses

Interest income represents income we earned on our excess cash balances held during the year. The increase of approximately \$0.5 million during 2000 arises from the additional funds available from two private placements we completed during the year and from the divesture of our Russian projects. Russian litigation costs (down approximately \$0.3 million from 1999), depletion and depreciation (down \$1.3 million from 1999) and asset write downs (down \$2.5 million from 1999) all result from the divesture of our Russian projects and the settlement of our legal dispute with our Russian partner in August 2000.

Income Taxes

We have significant tax losses available to carry forward and reduce taxes otherwise payable. Given the uncertainty as to the utilization of these tax loss carry-forwards, we have followed the practice of recording a provision against the tax benefit asset resulting from these losses. In 2000, our expected income tax expense on the income reported on our statement of income has been reduced by the benefit of tax assets not previously recorded.

Exploration and Development Activities

During 2000, we carried out an extensive exploration program in the San Joaquin Valley on acreage primarily acquired under our Aera exploration agreement. We participated in an 80,000 acre 3-D seismic shoot, the largest ever carried out in the San Joaquin Valley. We purchased an additional 7,000 acres of 3-D seismic previously shot in the same area. We also continued interpreting over 2,000 miles of 2-D seismic acquired in 1999. We submitted preliminary prospects to Aera for its review in 14 areas covered by the Aera exploration agreement. We are developing numerous drillable prospects within those preliminary prospect areas and, during 2000, we submitted six drillable prospects to Aera. At South Midway Sunset, where we have a 100% interest, we commenced a drilling program, details of which are discussed above under "Production". In addition to the South Midway Sunset drilling program, we drilled three other exploration wells in the San Joaquin Valley during 2000, two of which were dry and abandoned. We are still testing the third well to determine its commercial potential. We identified the location of our first deep gas well at Northwest Lost Hills and we expect to spud the well during the second quarter of 2001.

In Texas, we drilled 16 successful wells in our Spraberry Trend acreage in West Texas by year-end and an additional four wells during the first two months of 2001. Through a series of transactions in late 2000 and early 2001, we were successful in acquiring an interest in over 28,400 gross (20,700 net) acres in the Bossier gas sands in East Texas. We expect to commence drilling at Bossier during the third quarter of 2001.

At our Dagang Project in China, we completed our pilot testing phase in February, 2001. During 2000, as part of the pilot testing phase, we placed in production four new wells. We placed our initial well on water injection late in 2000 to evaluate the waterflood potential of the field. We also placed on production a fifth well in early 2001. We have decided to proceed to the development stage of our Dagang Project, which will require the submission of an overall development plan to the Chinese government for approval. We expect to submit it to the Chinese government during the second half of 2001. In the interim, we will continue to operate the pilot wells with production revenue accruing to us. At our Daqing Project, our overall development plan was approved in February, 2001 and we expect to start implementing it during the third quarter of 2001. Although we completed the pilot testing phase of the Daqing Project in 1998, we delayed submitting our overall development plan to the Chinese government because of low world oil prices and in order to focus our attention on our Dagang Project. In the interim, we agreed with CNPC to temporarily cede our operatorship of the Zhaozhou field pending completion and approval of our overall development plan for the Daqing Project. Having submitted and received approval for the Daqing Project, we expect to resume our role as operator during the first quarter of 2001.

The following summarizes the production and revenue we realized from the pilot testing phase of our Dagang Project. Prior to deciding to proceed to the development phase, this revenue was credited to the China cost pool for accounting purposes. All sales of oil are at or about WTI less approximately \$2.00 for quality and transportation. We receive all proceeds in U.S. dollars offshore China.

	2000	1999
Oil production (net) — Bbls	102,708	4,334
Price per Bbl realized	\$ 28.26	\$ 21.27
Total proceeds	<u>\$2,903,000</u>	<u>\$92,203</u>

Our total capital spending on oil and gas operations, including non-cash transactions, during 2000, compared to 1999, was as follows:

	2000	1999
	(in thousands)	
Capital expenditures — United States	\$22,816	\$ 9,644
— China	5,676	8,811
— Russia.....	<u>—</u>	<u>1,283</u>
	<u><u>\$28,492</u></u>	<u><u>\$19,738</u></u>
Comprised of: — Property acquisition	\$ 6,392	\$ 6,876
— Royalty acquisition	1,157	4,023
— Seismic	3,840	3,442
— Exploration	667	1,311
— Development	<u>19,376</u>	<u>4,178</u>
	<u><u>31,432</u></u>	<u><u>19,830</u></u>
Less: China oil production	<u>(2,940)</u>	<u>(92)</u>
	<u><u>\$28,492</u></u>	<u><u>\$19,738</u></u>

Gas-to-Liquids

During 2000, we acquired a master license from Syntroleum which allows us to use Syntroleum's proprietary GTL technology in an unlimited number of GTL projects throughout the world excluding North America, China and India. The Syntroleum GTL process converts natural gas into synthetic liquid hydrocarbons that can be utilized to develop cleaner-burning diesel fuel and other synthetic petroleum products. We have commenced engineering studies and review of several potential sites for our first GTL

plant and we are in advanced discussions with national petroleum corporations in the Middle East and Asia.

On October 5, 2000, we signed a letter of intent with Syntroleum to acquire a 13% non-recourse partnership interest in Syntroleum's Sweetwater GTL project under development in Western Australia. The plant, which will be located on the Burrup Peninsula in Western Australia, will convert natural gas contracted from the North West Shelf Venture Partners into ultra clean synthetic specialty products, such as lubricants, industrial fuel and paraffins, as well as synthetic fuels.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We have exploration and development projects in the United States and China. Our projects are at various stages and, like all exploration companies in the oil and gas industry, we are exposed to the significant risk that our exploration activities will not necessarily result in a discovery of economically extractable reserves.

We currently have limited production. Until June, 1999, we had a successful producing project in Russia, but legal actions initiated in the Russian courts by our Russian joint venture partner deprived us of the right to operate the field and to realize any continuing return on our investment. As a result, we sold our interest in the project in August 2000. Oil and gas revenue reported before 2000 was generated from our share of production from the Russian project.

Given our limited production, we have limited exposure to commodity price risks. We are exposed to the risk that we may require a provision for impairment as to the carrying value of our oil and gas assets. The carrying value of our capitalized oil and gas assets is compared quarterly to the estimated recoverable value of our proved reserves based on period-end commodity prices, unescalated. We are exposed to the risk that we will be unable to engage competent cost-effective contractors and suppliers for our operations, risks that damage to, or malfunction of, our equipment will hinder our ability to carry out our exploration activities and risks that foreign laws may not adequately protect our interests in disputes with foreign partners and others.

In the international petroleum industry, most production is bought and sold in United States currency or with reference to United States currency. Accordingly, we do not expect to face foreign exchange risks if and when we commence large scale commercial production. Most of our business transactions are conducted in United States currency in the countries in which we operate.

We currently have minimal debt obligations and, therefore, we do not believe that we face any undue financial risk from interest rate fluctuations and we are not currently involved in any transactions of a hedging nature.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA**Index to Financial Statements and Related Information**

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AUDITORS' REPORT

To the Shareholders of
Ivanhoe Energy Inc.:

We have audited the consolidated balance sheets of Ivanhoe Energy Inc. as at December 31, 2001 and 2000 and the consolidated statements of loss (income) and deficit and cash flow for each of the years in the three year period ended December 31, 2001. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

With respect to the consolidated financial statements for each of the years in the two year period ended December 31, 2001 we conducted our audit in accordance with Canadian generally accepted auditing standards, and United States generally accepted auditing standards. With respect to the consolidated financial statements for the year ended December 31, 1999, we conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2001 and 2000 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2001 in accordance with Canadian generally accepted accounting principles.

Calgary, Alberta
February 8, 2002

(signed) Deloitte & Touche LLP
Chartered Accountants

COMMENTS BY AUDITORS FOR U.S. READERS ON CANADA — U.S. REPORTING DIFFERENCES

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when the financial statements are affected by conditions and events that cast uncertainty as to the Company's ability to carry out and complete planned activities without raising additional financing, as described in Note 1 to the financial statements. Our report to the shareholders dated February 8, 2002 is expressed in accordance with Canadian reporting standards which do not permit a reference to such events and conditions in the auditor's report when these are adequately disclosed in the financial statements.

In addition, in the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) outlining changes in accounting principles that have been implemented in the financial statements. As discussed in Note 11 to the financial statements, in 2001 the Company changed its method of computing diluted earnings per share to conform to the new Canadian Institute of Chartered Accountants Handbook recommendations section 3500.

Calgary, Alberta
February 8, 2002

(signed) Deloitte & Touche LLP
Chartered Accountants

IVANHOE ENERGY INC.
Consolidated Balance Sheets
(stated in thousands of U.S. Dollars)

	As at December 31,	
	2001	2000
Assets		
Current Assets		
Cash and cash equivalents	\$ 9,697	\$29,694
Accounts receivable	1,938	4,532
Other	375	872
	12,010	35,098
Long term assets	397	242
Oil and gas properties, equipment and GTL investments, net (Note 3)	91,596	64,460
	\$104,003	\$99,800
Liabilities and Shareholders' Equity		
Current Liabilities		
Accounts payable and accrued liabilities	\$ 5,974	\$ 2,951
Convertible debenture (Note 4)	1,000	1,000
	6,974	3,951
Provision for site restoration	132	11
Shareholders' Equity		
Share capital (Note 5)	120,392	98,211
Deficit	(23,495)	(2,373)
	96,897	95,838
	\$104,003	\$99,800

Approved by the Board:

(signed) David Martin
Director

(signed) Leon Daniel
Director

IVANHOE ENERGY INC.

**Consolidated Statements of Loss (Income) and Deficit
(stated in thousands of U.S. Dollars, except per share data)**

	Year ended December 31,		
	2001	2000	1999
Revenue			
Petroleum and natural gas revenue	\$ 9,144	\$ 851	\$ 5,460
Operating revenue	—	—	296
Interest income	578	990	454
Gain on sale of Russian projects (Note 9)	—	12,222	—
	9,722	14,063	6,210
Expenses			
Operating costs	4,758	787	4,219
Project identification costs	6,210	3,732	1,735
General and administrative	2,635	2,914	2,693
Russian litigation	—	860	1,134
Depletion and depreciation	3,241	341	1,714
Provision for impairment (Note 8)	14,000	—	2,517
	30,844	8,634	14,012
Net Loss (Income) (Note 10)	21,122	(5,429)	7,802
Deficit, beginning of year	2,373	7,802	74,455
Transfer of deficit to share capital (Note 5)	—	—	(74,455)
Deficit, end of year	\$ 23,495	\$ 2,373	\$ 7,802
Net Loss (Income) per share (Note 11)			
Basic	\$ 0.16	\$ (0.05)	\$ 0.08
Diluted	\$ 0.16	\$ (0.04)	\$ 0.08
Weighted Average Number of Shares (in thousands)			
(Note 11)			
Basic	128,598	119,719	99,687
Diluted	128,598	124,549	99,687

IVANHOE ENERGY INC.

Consolidated Statements of Cash Flow
(stated in thousands of U.S. Dollars)

	Year ended December 31,		
	2001	2000	1999
Operating Activities			
Net (loss) income	\$(21,122)	\$ 5,429	\$ (7,802)
Items not requiring use of cash			
Gain on sale of Russian projects (Note 9)	—	(12,222)	—
Provision for impairment (Note 8)	14,000	—	2,517
Depletion and depreciation	3,241	341	1,715
Other	—	67	47
Changes in non-cash working capital items	6,314	(5,448)	(2,707)
	<u>2,433</u>	<u>(11,833)</u>	<u>(6,230)</u>
Investing Activities			
Oil and gas properties, equipment and GTL investments	(40,504)	(40,827)	(10,728)
Recovery from Russian projects	—	31,710	5,550
Other	(155)	292	(392)
	<u>(40,659)</u>	<u>(8,825)</u>	<u>(5,570)</u>
Financing Activities			
Shares issued on private placements (net)	17,903	38,598	—
Shares issued on exercise of options and warrants	326	9,117	735
	<u>18,229</u>	<u>47,715</u>	<u>735</u>
Increase (decrease) in cash and cash equivalents, for the year	(19,997)	27,057	(11,065)
Cash and cash equivalents, beginning of year	29,694	2,637	13,702
Cash and cash equivalents, end of year	<u>\$ 9,697</u>	<u>\$ 29,694</u>	<u>\$ 2,637</u>
Supplementary Information Regarding Non-Cash Transactions			
Investing activities, net assets acquired:			
Overriding royalties	\$ 2,852	\$ 917	\$ 3,163
Lease acquisition	900	—	568
Accounts receivable	200	—	—
Acquisition of China assets	—	—	5,279
	<u>\$ 3,952</u>	<u>\$ 917</u>	<u>\$ 9,010</u>
Financing activities, non-cash:			
Shares issued as consideration	\$ 3,952	\$ 917	\$ 9,010
Included in the above are the following:			
Taxes paid	<u>\$ 104</u>	<u>\$ 8</u>	<u>\$ 199</u>
Interest paid	<u>\$ 111</u>	<u>\$ 120</u>	<u>\$ 86</u>
Decrease (increase) in non-cash working capital items			
Accounts receivable	\$ 2,794	\$ (3,182)	\$ (673)
Other current assets	497	(248)	1,967
Accounts payable and accrued liabilities	3,023	(2,018)	(4,001)
	<u>\$ 6,314</u>	<u>\$ (5,448)</u>	<u>\$ (2,707)</u>

IVANHOE ENERGY INC.

Notes to the Consolidated Financial Statements (expressed in U.S. Dollars with amounts in tables being in thousands, except per share data)

1. NATURE OF OPERATIONS

Ivanhoe Energy Inc., a Canadian company, and its subsidiaries are focused internationally on three major strategies: 1) exploration and development of hydrocarbons 2) enhanced oil recovery and 3) the application of gas-to-liquids technology. Operations are currently carried out in the United States and China.

The Company's activities contemplate significant capital expenditures to develop its properties and projects. Significant financing will need to be raised through equity, debt financing and joint venture partner participation in order to complete the planned activities. In the event that such financing is not available to the Company, it will be necessary to prioritize activities, which may result in delaying and potentially losing business opportunities and causing potential impairment to recorded assets.

2. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in Canada. The consolidated financial statements also conform in all material respects to United States GAAP, except for the following matters for which details are provided in the referenced notes: — the price per share used to record the acquisition of royalty interests (Note 3); — reduction of the deficit as at December 31, 1998 (Note 5); — net loss (income) for the year as a result of an additional ceiling test required under United States GAAP and the requirement to write-off capitalized development costs incurred in connection with our GTL prospects, net loss (income) per share calculations, and additional disclosures required under United States GAAP (Note 15).

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts and other disclosures in these consolidated financial statements. Actual results may differ from those estimates.

Principles of Consolidation

These consolidated financial statements include the accounts of Ivanhoe Energy Inc. and its subsidiaries, all of which are wholly owned.

All inter-company transactions and balances have been eliminated for the purposes of these consolidated financial statements.

Foreign Currency Translation

The Company uses the United States Dollar as its functional currency since it is the currency of the economic environments in which the Company and its subsidiaries operate. Monetary assets and liabilities denominated in foreign currencies are converted at the exchange rate in effect at the balance sheet date and non-monetary assets and liabilities at the exchange rates in effect at the time of acquisition or issue. Revenues and expenses are converted at rates approximating exchange rates in effect at the time of the transactions. Exchange gains or losses resulting from the translation of foreign currency amounts are reflected in operations.

Cash and Cash Equivalents

Cash and cash equivalents include short-term money market instruments with terms to maturity, at the date of issue, not exceeding 90 days.

Financial Instruments

The fair value of the Company's cash, accounts receivable, notes receivable, accounts payable and accrued liabilities approximates the carrying values due to the immediate or short-term maturity of these financial instruments.

The estimated fair value of the convertible debenture at December 31, 2001 is approximately \$1,442,000, (December 31, 2000 — \$1,790,000).

Oil and Gas Properties

The Company follows the full cost method of accounting for oil and gas operations whereby all exploration and development expenditures are capitalized on a country-by-country cost centre basis. Such expenditures include land acquisition costs, geological and geophysical expenses, carrying charges for unproved properties, costs of drilling both productive and non-productive wells, gathering and production facilities and equipment, and financing and administrative costs related to capital projects. Proceeds from sales of oil and gas properties are recorded as reductions of capitalized costs, unless such amounts would significantly alter the rate of depreciation and depletion, whereupon gains or losses would be recognized in income. Maintenance and repair costs are expensed as incurred, while improvements and major renovations are capitalized.

Costs of oil and gas properties accumulated within each cost centre, including a provision for future development costs, are depleted using the unit of production method based on estimated proved reserves. Significant development projects and expenditures on exploration properties are excluded from the depletion calculation until evaluated. These excluded costs are evaluated periodically for impairment.

Royalties acquired are included in oil and gas properties and recorded at cost.

Depletable costs, accumulated in each cost centre, net of depletion provided, future income taxes and accumulated site restoration costs, are compared annually to the non-discounted estimated future net revenues from proved reserves (based on year-end non-escalated prices), net of estimated administration and carrying costs, and related production and income taxes ("ceiling test"). Any accumulated costs in excess of the calculated ceiling test are charged to operations.

Provision for Future Site Restoration

The Company has developed an estimate for future site restoration and abandonment costs and is amortizing this estimate to operations using the unit-of-production method based upon estimated proved reserves. The provision is included with depletion and depreciation expense.

Furniture and Fixtures

Furniture and fixtures are stated at cost. Depreciation is provided on a straight-line basis over the estimated useful life of the respective assets, at rates ranging from three to ten years.

Petroleum and Natural Gas Revenue

Sales of crude oil and natural gas are recognized in the period in which the product is delivered to the customer.

Loss (Income) Per Share

The loss (income) per share is computed on the basis of the weighted average number of shares outstanding during each year. Effective January 1, 2001, the Company adopted, retroactively, the treasury stock method to determine diluted earnings per share (See Note 11).

Income Taxes

The Company follows the liability method of accounting for future income taxes, which it adopted retroactively in the year ended December 31, 2000. Under the liability method, future income taxes are recognized to reflect the expected future tax consequences arising from tax loss carry-forwards and temporary differences between the carrying value and the tax basis of the Company's assets and liabilities.

Stock Based Compensation Plan

The Company has an Employees' and Directors' Equity Incentive Plan consisting of stock option, bonus and share purchase incentives (Note 5). Options are granted at market price and no compensation expenses are recognized when stock options are issued or exercised. Consideration paid upon exercise of stock options is credited to share capital. Compensation expenses are recognized when shares are issued from the stock bonus plan. The share purchase portion of the plan has not yet been activated.

3. OIL AND GAS PROPERTIES, EQUIPMENT AND GTL INVESTMENTS

Capital assets categorized by geographic location are as follows:

	December 31, 2001			December 31, 2000		
	U.S.	China	Total	U.S.	China	Total
Oil and gas properties and equipment	\$65,997	\$25,427	\$91,424	\$32,349	\$18,887	\$51,236
Accumulated depletion	(2,143)	(1,124)	(3,267)	(254)	—	(254)
Provision for impairment	(14,000)	—	(14,000)	—	—	—
	<u>49,854</u>	<u>24,303</u>	<u>74,157</u>	<u>32,095</u>	<u>18,887</u>	<u>50,982</u>
Gas to Liquids Investments						
Master license	10,000	—	10,000	10,000	—	10,000
Investment in Sweetwater partnership	2,000	—	2,000	2,000	—	2,000
Feasibility studies and other deferred costs	5,142	—	5,142	1,253	—	1,253
	<u>17,142</u>	<u>—</u>	<u>17,142</u>	<u>13,253</u>	<u>—</u>	<u>13,253</u>
Furniture and fixtures	467	—	467	262	—	262
Accumulated depreciation	(170)	—	(170)	(37)	—	(37)
	<u>297</u>	<u>—</u>	<u>297</u>	<u>225</u>	<u>—</u>	<u>225</u>
	<u><u>\$67,293</u></u>	<u><u>\$24,303</u></u>	<u><u>\$91,596</u></u>	<u><u>\$45,573</u></u>	<u><u>\$18,887</u></u>	<u><u>\$64,460</u></u>

Costs as at December 31, 2001 of \$40,267,000 (2000 — \$24,822,000; 1999 — \$12,767,000) related to unevaluated oil and gas properties are excluded from the depletable cost pools.

For the year ended December 31, 2001 general and administrative expenses related directly to acquisition, exploration, development and GTL activities of \$3,636,000 (2000 — \$1,549,000; 1999 — \$898,000) were capitalized.

Gas-to-Liquids

During 2000, the Company acquired a master license from Syntroleum Corporation permitting the Company to use Syntroleum's proprietary gas-to-liquid process ("GTL") in an unlimited number of GTL projects around the world except North America, China and India. The Syntroleum process converts natural gas into synthetic liquid hydrocarbons that can be utilized to develop, among other things, cleaner-burning diesel fuel. The Company views the process as holding significant potential for monetizing uneconomic stranded natural gas reserves in large gas-prone regions of the world.

On October 5, 2000, the Company signed a letter of intent with Syntroleum to acquire a 13% non-recourse partnership interest in Syntroleum's Sweetwater GTL project in Western Australia. Under the terms of the letter of intent, the Company's 13% interest will cost a total of \$21,000,000, of which \$2,000,000 has been paid and will be used by Syntroleum, solely to fund front-end engineering and other project engineering expenses. Payment of the remaining \$19,000,000 is subject to satisfaction of various conditions, including Syntroleum obtaining project financing. The Company's participation does not require any further financial commitments and entitles the Company to participate in 13% of the project cash flow each year. Syntroleum is continuing the process of refining the cost structure of the GTL facilities and securing financing for the project.

The Company has undertaken detailed project feasibility studies for the construction, operation and cost of world class GTL plants in both Qatar and Egypt. In addition, the Company conducted two marketing and one transportation feasibility studies. Marketing studies were conducted for both Europe and the Asia-Pacific regions for GTL diesel and naphtha. Markets within these regions were identified and premiums for the GTL ultra clean fuels were estimated. Product forecasts from these studies will be used as the basis for evaluating the commerciality of each of the GTL projects. All cost associated with these two projects have been capitalized.

Recovery of the GTL costs capitalized is dependent upon finalizing contracts to access natural gas reserves in the respective countries and the successful completion of GTL processing plants. For United States GAAP purposes development costs associated with the Company's GTL prospects of \$5,142,000 have been written off.

United States

In 1998, the Company acquired rights to an exploration agreement with Aera Energy LLC ("Aera") in an area of more than 250,000 acres in the Southern San Joaquin Valley in California. The Aera Exploration Agreement ("Agreement") gave the Company the right, which expired on September 15, 2001, access to all of Aera's exploration, seismic and technical data in the region for the purpose of identifying drillable exploration prospects within the exclusive area. The Agreement provided the Company the right to a working interest ownership in all drillable prospects in which Aera elects to participate equal to a minimum of 12.5% and a maximum of 75%. In those prospects in which Aera elects not to participate the Company has the right to proceed with a 100% working interest and to seek other joint venture partners. Aera has the right to act as the operator for any drillable prospects in which Aera elects to participate.

During the term of the Agreement, the Company submitted to Aera 18 prospect Areas of Mutual Interest ("AMIs") containing a total of over 40 prospects. Aera has elected to participate in 12 AMIs in which the Company will have working interests ranging from 12.5% to 50%. In the 3 AMIs where Aera has elected not to participate, the Company will have a 100% working interest. In 2 of the AMIs Aera has not yet made an election to participate. In the remaining AMI neither Aera nor the Company has elected to participate and subsequent to year end have farmed out the prospect, retaining an overriding royalty interest.

In addition to prospects under the Agreement the Company has acquired other percentage interests in Southern California, West Texas, Kentucky and the Bossier Trend in east Texas.

The Company has leased mineral rights in 58,000 gross (44,000 net) acres in the Bossier Trend in east Texas and has entered into joint venture agreements with a subsidiary of Unocal Corp. ("Unocal") under which Unocal will earn a 50% interest in the Company's holdings by expending the next \$10 million of costs associated with exploration and development of prospects.

China

During the year the Company held two production-sharing contracts to develop existing oil fields in the Daqing and Dagang regions of the People's Republic of China. Basically the Company incurs 100% of the

costs to earn approximately 82% of the production, before recovery of costs incurred, reverting to a 49% share post recovery.

Each contract calls for the planning and completion of a pilot testing phase to assess the technological and economic viability of the project, followed by a full field development plan and implementation.

At the Company's Dagang project, the pilot testing phase was completed in February 2001. Nippon Oil Exploration Limited of Japan, earned a 20% working interest in the Company's interest in the project by funding a disproportionate share of the Dagang pilot testing expenditures. In August 2001 Nippon decided to withdraw from the project and their interest reverted back to the Company. The decision was made to proceed with the preparation of the development plan for submission to CNPC. Submission of the final draft and subsequent approval is expected in 2002. During the development plan preparation and approval process the Company will continue operatorship of the Dagang project.

At Daqing, the pilot program was completed successfully in 1998. While the decision was made to continue on to the field development plan, the Company chose to delay the process and, by agreement, CNPC took over operatorship of the field and the right to all revenue generated and responsibility for all costs incurred. The field development plan was completed in 2000 and approved by the relevant regulatory agencies in February 2001. Operatorship reverted back to the Company on March 1, 2001. During 2001 the Company negotiated with CNPC for additional blocks to be included in the contract area. Negotiations were unsuccessful and after an internal review of the Company's China projects, and the decision to concentrate on major gas developments in China, the Daqing project was put up for disposal. Effective January 22, 2002 the Company was successful in disposing of the project for \$2,400,000 and an overriding royalty on future production. (Note 13)

During the pilot testing phase at Dagang and Daqing, for accounting purposes, all production costs and revenues were capitalized. With the evaluation stage completed and the decision made to enter the development and implementation stage, all operating results beginning January 1, 2001 for Dagang and March 1, 2001 for Daqing are included in the Company's operations.

During the year the Company signed two memorandums of understanding with PetroChina Company Limited ("PetroChina"), which gives the Company the exclusive right to negotiate petroleum contracts with PetroChina to develop and exploit the oil and gas resources in three key blocks within the Sichuan basin, China's largest gas-producing region. The Company signed Joint Study Agreements with PetroChina covering the three blocks and outlining the joint activities and technical requirements of both parties prior to entering into contract negotiations. At year-end the Company was still in the process of assessing the oil and gas resources and potential development plan.

Overriding Royalties

Through a series of transactions the Company has acquired overriding royalties in AMI prospects in California ranging from 1.4637% to 6.58% in consideration for \$860,000 cash and the issuance of 2,885,000 common shares at an aggregate ascribed value of \$8,032,000, being 1,562,000 common shares at \$2.02 (Cdn.\$2.98); 523,000 common shares at \$1.76 (Cdn.\$2.55) and 800,000 common shares at \$4.94 (Cdn.\$7.59). Of the total consideration paid in 2001, \$900,000 was allocated to lease acquisition and \$200,000 to accounts receivable.

For United States GAAP purposes, the aggregate value attributed to the royalty acquisitions is \$1,358,000 higher, due to the difference between the value ascribed to the shares issued between Canadian and United States GAAP, primarily resulting from differences in the recognition of effective dates of the transactions.

4. CONVERTIBLE DEBENTURE

The \$1,000,000 unsecured convertible debenture bears interest at United States prime plus 2.5%, is due on the earlier of August 4, 2002 or within 90 days following written demand, and is convertible into

common shares (principal and interest, accrued and unpaid, all or in part) of the Company at Cdn.\$2.75 per share up to August 4, 2002.

5. SHARE CAPITAL

The authorized capital of the Company consists of an unlimited number of common shares without par value and an unlimited number of preferred shares without par value.

The total number of issued and outstanding common shares is as follows:

	Number of Common Shares (thousands)	Amount
Balance December 31, 1998.....	89,694	\$114,157
Issued on exercise of options	1,162	735
Issued for service	25	47
Issued for acquisitions	19,658	9,010
Reduction of stated capital	<u>—</u>	<u>(74,455)</u>
Balance December 31, 1999.....	110,539	\$ 49,494
Issued for Private Placements, net.....	11,250	38,598
Issued on exercise of warrants	2,998	8,083
Issued on exercise of options	1,545	1,034
Issued on acquisition of overriding royalties (Note 3)	523	917
Issued for services	<u>19</u>	<u>85</u>
Balance December 31, 2000.....	126,874	98,211
Issued for Private Placements, net.....	11,260	17,903
Issued on exercise of warrants	127	166
Issued on exercise of options	206	160
Issued on acquisition of overriding royalties (Note 3)	<u>800</u>	<u>3,952</u>
Balance December 31, 2001.....	<u>139,267</u>	<u>\$120,392</u>

The December 31, 2001 share dollar amount is net of loans of \$409,000 (December 31, 2000 — \$236,000) advanced to an employee and two directors to assist in the exercise of incentive stock options as permitted under the Employees' and Directors' Equity Incentive Plan.

Private Placements and Share Purchase Warrants

Under a private placement in October 2001, the Company issued 11,260,000 common shares at \$1.60, net of expenses of \$113,000.

During 2000, the Company issued common shares under two private placements. In January and February 2000, the Company issued 6,250,000 units, each unit consisting of one common share and one share purchase warrant, for net proceeds of \$14,014,000. Each two warrants were exercisable into one common share at Cdn.\$4.00 until the first anniversary date of the private placement. At December 31, 2001 all of these warrants were exercised. On October 17, 2000, the Company issued 5,000,000 units, each unit consisting of one common share and one share purchase warrant, for net proceeds of \$24,584,000. Each two warrants were exercisable into one common share at \$5.375 until October 17, 2002. At December 31, 2001, all of the warrants remain outstanding for purchase of 2,500,000 common shares.

Reduction of Stated Capital

The shareholders approved, on June 22, 1999, the reduction of stated capital in respect of the common shares by an amount of \$74,455,000 being equal to the accumulated deficit as at December 31, 1998. Under United States GAAP, a reduction of the deficit such as this is not recognized except in the case of

a quasi reorganization. The effect of this is that under United States GAAP, share capital and deficit each are increased by \$74,455,000 at December 31, 2001 and 2000.

Equity Incentive Plan

The Company has an Employees' and Directors' Equity Incentive Plan under which it can grant stock options to directors, officers and employees to purchase common shares, issue common shares to directors and employees for bonus awards and issue shares under a share purchase plan for employees.

Stock options are issued at the quoted market value on the date of the grant, are conditional on continuing employment and vest at the discretion of the Board of Directors. Options granted vest over a four year period and expire five years from the date of issue except those granted prior to March 1, 1999 which vest over a two year period and expire ten years from date of issue.

Following is a summary of the stock option portion of the Company's Equity Incentive Plan, including changes during the years ended:

	December 31, 2001		December 31, 2000		December 31, 1999	
	Number of Shares (000's)	Weighted-Average Exercise Price (Cdn.\$)	Number of Shares (000's)	Weighted-Average Exercise Price (Cdn.\$)	Number of Shares (000's)	Weighted-Average Exercise Price (Cdn.\$)
Outstanding at beginning of year ...	8,161	\$2.45	7,800	\$1.18	8,090	\$0.93
Granted	846	4.63	1,991	6.39	2,065	2.56
Exercised	(206)	1.40	(1,545)	1.20	(1,162)	1.33
Cancelled/forfeited	(166)	4.04	(85)	1.09	(1,193)	1.75
Outstanding at end of year	<u>8,635</u>	<u>\$2.66</u>	<u>8,161</u>	<u>\$2.45</u>	<u>7,800</u>	<u>\$1.18</u>
Options exercisable at year end	<u>6,089</u>	<u>\$1.73</u>	<u>5,356</u>	<u>\$1.24</u>	<u>4,328</u>	<u>\$0.92</u>

The following table summarizes information respecting stock options outstanding at December 31, 2001:

Range of Exercise Prices (Cdn.\$)	Options Outstanding			Options Exercisable	
	Number Outstanding (000's)	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price (Cdn.\$)	Number Exercisable (000's)	Weighted-Average Exercise Price (Cdn.\$)
\$0.50 to \$1.75	4,296	7.1 years	\$0.58	4,296	\$0.58
\$2.50 to \$3.60	2,044	3.1 years	\$2.87	943	\$2.79
\$5.15 to \$7.62	2,295	3.7 years	\$6.36	850	\$6.37
\$0.50 to \$7.62	<u>8,635</u>	<u>5.2 years</u>	<u>\$2.66</u>	<u>6,089</u>	<u>\$1.73</u>

Subsequent to December 31, 2001, the Company issued 201,000 common shares from the bonus awards portion of the Equity Incentive Plan, to directors, officers and employees as part of a deferred compensation program implemented for the fourth quarter 2001. The total compensation amount is accrued in the 2001 statement of loss (income) and deficit.

6. RETIREMENT PLAN

In 2001 the Company adopted a defined contribution retirement or thrift plan (401(k) Plan) to assist United States employees in providing for retirement or other future financial needs. Employees' contributions (up to the maximum allowed by United States tax laws) are matched 50% by the Company in 2001 and increasing 10% per year thereafter to a maximum of a 100%. The cost of Company contributions to the plan during 2001 amounted to \$78,000.

7. SEGMENT INFORMATION

Geographic segment results from operations for the years ended December 31, 2001, 2000 and 1999 are detailed below. The Company maintains a corporate office in Canada with its operational office in the USA. For this section any amounts for Canada are included in the USA segment.

	Year ended December 31, 2001		
	U.S.	China	Total
Petroleum and natural gas revenue	\$ 5,101	\$ 4,043	\$ 9,144
Interest income	578	—	578
	<u>5,679</u>	<u>4,043</u>	<u>9,722</u>
Operating costs	2,421	2,337	4,758
Depletion and depreciation	2,117	1,124	3,241
Provision for impairment	14,000	—	14,000
	<u>18,538</u>	<u>3,461</u>	<u>21,999</u>
Loss (income) before the following	\$12,859	\$ (582)	12,277
Project identification costs			6,210
General and administrative			2,635
Net loss			\$ 21,122
Capital expenditures — Acquired for cash	\$33,936	\$ 6,568	\$ 40,504
— Acquired for shares	<u>3,752</u>	<u>—</u>	<u>3,752</u>
	<u>\$37,688</u>	<u>\$ 6,568</u>	<u>\$ 44,256</u>
Identifiable assets — Oil and gas	\$61,750	<u>\$25,067</u>	\$ 86,817
— Gas-to-liquids			17,186
			<u>\$104,003</u>
	Year ended December 31, 2000		
	U.S.	China	Total
Petroleum and natural gas revenue	\$ 851	\$ —	\$ 851
Interest income	982	8	990
	<u>1,833</u>	<u>8</u>	<u>1,841</u>
Operating costs	787	—	787
Depletion and depreciation	310	31	341
	<u>1,097</u>	<u>31</u>	<u>1,128</u>
Income (loss) before the following	\$ 736	\$ (23)	713
Project identification costs			3,732
General and administrative			2,914
Gain on sale of Russian projects			(12,222)
Russian litigation			860
Net income			\$ 5,429
Capital expenditures — Acquired for cash	\$35,151	\$ 5,676	\$ 40,827
— Acquired for shares	<u>917</u>	<u>—</u>	<u>917</u>
	<u>\$36,068</u>	<u>\$ 5,676</u>	<u>\$ 41,744</u>
Identifiable assets — Oil and gas	\$65,711	<u>\$20,836</u>	\$ 86,547
— Gas-to-liquids			13,253
			<u>\$ 99,800</u>

	Year ended December 31, 1999			
	U.S.	China	Russia	Total
Petroleum and natural gas revenue	\$ —	\$ —	\$5,460	\$ 5,460
Operating revenue	—	—	296	296
Interest income	398	1	55	454
	398	1	5,811	6,210
Operating costs	—	—	4,219	4,219
Depletion and depreciation	35	14	1,665	1,714
Provision for impairment	2,517	—	—	2,517
	2,552	14	5,884	8,450
Loss before the following	<u>\$2,154</u>	<u>\$ 13</u>	<u>\$ 73</u>	<u>2,240</u>
Project identification costs				1,735
General and administrative				2,693
Russian litigation				1,134
Net loss				<u>\$ 7,802</u>
Capital expenditures — Acquired for cash	\$5,913	\$ 3,532	\$1,283	\$10,728
— Acquired for shares	<u>3,731</u>	<u>5,279</u>	<u>—</u>	<u>9,010</u>
	<u>\$9,644</u>	<u>\$ 8,811</u>	<u>\$1,283</u>	<u>\$19,738</u>

During 2001, three customers accounted for 100% of the total sales in the United States, being 49%, 40% and 11% respectively. In China 100% of the 2001 sales were made to the China National Petroleum Corporation.

In the United States during 2000, three customers accounted for 96% of total sales being 44%, 40% and 12% respectively. In 1999, the Company derived 96% of its Russia sales from two customers, being 85% and 11% respectively.

8. PROVISION FOR IMPAIRMENT

Provision for impairment amounts determined under Canadian GAAP include the following:

	Year Ended December 31,		
	2001	2000	1999
Provision for impairment of United States oil and gas properties	\$14,000	\$ —	\$ —
Write down of Russian oil and gas equipment to estimated net realizable value and other	—	—	2,517
	<u>\$14,000</u>	<u>\$ —</u>	<u>\$2,517</u>

On application of United States GAAP an additional provision for impairment, with respect to the Company's China properties, of \$10,000,000 is required. No impairment provisions were required for 2000 or 1999. (See Note 15 — U.S. GAAP Disclosures)

9. GAIN ON SALE OF RUSSIAN PROJECTS

In August 2000, a negotiated settlement was reached resulting in the disposition of the Company's Russian projects for cash proceeds of \$28,182,000, net of \$840,000 of settlement and severance costs. The proceeds exceeded the then carrying value of the Company's investment in the Russian projects and the resulting gain of \$12,222,000 was included in income. Until June 30, 1999, the date of loss of control, the Company proportionately consolidated Russian operations.

10. INCOME TAXES

The Company and its subsidiaries are required to individually file tax returns in each of the jurisdictions in which they operate. Details of the determination of the actual income tax expense for each of the three years are detailed below. For ease of presentation, the loss, as a result of the write down of Russian assets, and the subsequent gain on settlement has been classified as Russian operations, even though neither of these two items have any tax effect in Russia. The actual loss of approximately \$35 million, being the aggregate investment, ignoring accounting write downs, less proceeds received on settlement will be a capital loss for Canadian income tax purposes, available for carry-forward against future Canadian capital gains indefinitely.

	Year Ended December 31,		
	2001	2000	1999
Source loss (income) before income taxes	\$21,122	\$(5,429)	\$ 7,802
Composite statutory income tax rate.....	43.20%	43.20%	42.78%
Expected income tax (recovery)	\$ (9,125)	\$ 2,345	\$(3,338)
Non-deductible expenses for tax purposes.....	—	—	78
Application of tax benefits not recognized previously	—	(4,910)	—
Tax benefit not recognized	9,125	2,565	3,260
Income tax expense	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>

The tax loss carry-forwards in Canada are Cdn. \$39,394,000 and in the United States \$40,752,000. The tax losses carry-forward in Canada expire between 2003 and 2008, in the United States between 2018 and 2021. In China the Company has available for carry-forward against future Chinese income \$37,193,000 of cost basis. In addition, the carrying value of assets for accounting purposes is \$28,861,000 greater than that available for tax purposes. Due to the uncertainty of utilizing these net tax assets, the Company has made a valuation allowance of an equal amount against these potential recoverable amounts as detailed below.

	As at December 31,		
	2001	2000	1999
Future net tax assets	\$27,082	\$23,909	\$23,439
Valuation allowance	(27,082)	(23,909)	(23,439)
Net future tax liability	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>

11. NET INCOME (LOSS) PER SHARE

The Company has adopted retroactively the treasury method to assess the potential impact of outstanding stock options, convertible debentures and share purchase warrants on earnings per share, as promulgated by Canadian GAAP. The treasury stock method conforms to the practice followed in the United States.

This change has resulted in a change to reported diluted net income per share for the year ended December 31, 2000 to \$0.04 from \$0.05 as previously reported. The number of shares used to calculate diluted earnings per share for the year ended December 31, 2000 of 124,549,000 included the weighted average number of shares outstanding of 119,719,000 plus 4,802,000 shares related to the dilutive effect of stock options and 28,000 shares related to share purchase warrants. For the year ended December 31, 2001, if the diluted calculation were performed for other than net loss, the number of shares which would have been used of 132,616,000 would have included the weighted average number of shares outstanding of 128,598,000 plus 4,018,000 shares related to the dilutive effect of stock options.

The diluted earnings per share computations discussed above did not include 240,000 (2000 — 724,000) of share options and 2,500,000 (2000 — 514,000) of share purchase warrants, both on a weighted

average basis, because the respective exercise prices exceeded the average market price of the common shares. Similarly, the number of shares, which would be issued on conversion of the convertible debenture, are not included as the effect would be anti-dilutive for 2001 and 2000.

12. RELATED PARTY TRANSACTIONS

The Company has entered into agreements with a number of entities, some of which are related through common directors or shareholders, to share administrative personnel, office space, and facilities. The Company is billed on a cost recovery basis. The costs incurred in the normal course of business with respect to the above arrangements amounted to \$2,650,000 for 2001, \$1,581,000 for 2000, and \$1,692,000 for 1999. In addition, a company controlled by a director provides consulting services to the Company. During the year \$673,000 was paid for such consulting services and out of pocket expenses. At year end amounts included in accounts payable under these arrangements totaled \$1,148,000 in 2001 and \$486,000 in 2000.

13. SUBSEQUENT EVENT

Effective January 22, 2002 the Company finalized the sale of its Daqing project to an unrelated party for \$2,400,000: \$1,200,000 cash on closing and a \$1,200,000 non-interest bearing promissory note receivable due on or before September 1, 2002. The Company also retains an overriding royalty of 4% before cost recovery and 2% thereafter. The sale proceeds will be credited to the full cost pool, (Note 2) as the sale does not represent a significant disposition of the China total reserve base.

14. COMPARATIVE FIGURES

Certain of the comparative amounts have been reclassified to conform to the presentation adopted for the current year.

15. ADDITIONAL DISCLOSURES REQUIRED UNDER UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES ("GAAP")

The Company's consolidated financial statements have been prepared in accordance with GAAP as applied in Canada. In the case of the Company, Canadian GAAP conforms in all material respects with United States GAAP, except for certain matters, which were mentioned in Note 2. Where these matters impact the financial statements, the details of the differences are as follows:

Consolidated Statements of Loss (Income)

As discussed under Oil and Gas Properties in this note, there is a difference in performing the ceiling test evaluation under full cost accounting between United States and Canadian GAAP. Application of the ceiling test evaluation under United States GAAP requires an additional \$10,000,000 provision for impairment with respect to the Company's China properties.

In addition, the capitalization of development costs permitted under Canadian GAAP in connection with our GTL prospects is not permitted under United States GAAP.

The Company, in connection with its initial public offering in June 1997, placed in escrow 31,457,000 common shares held by certain shareholders, to be released one-third per year on the succeeding three anniversary dates of the public offering. For Canadian GAAP, as the release of shares from escrow is based on time rather than on any performance criteria, these shares are considered issued and outstanding and form part of the calculation of earnings and fully dilutive earnings per share. Under United States GAAP, these escrow shares are considered issued and outstanding only after they are released from escrow.

Under United States GAAP, interest income and gain on sale of Russian projects would be classified as other income.

The application of United States GAAP has the following effects on net loss (income) and net loss (income) per share as reported:

	Year ended December 31,		
	2001	2000	1999
Net loss (income) under Canadian GAAP	\$21,122	\$ (5,429)	\$7,802
Additional provision for impairment under United States GAAP	10,000	—	—
Write off of GTL development costs under United States GAAP	5,142	—	—
Net loss (income) under United States GAAP	<u>\$36,264</u>	<u>\$ (5,429)</u>	<u>\$7,802</u>
Net loss (income) per share under United States GAAP			
Basic	\$ 0.28	\$ (0.05)	\$ 0.09
Diluted	\$ 0.28	\$ (0.05)	\$ 0.09
Weighted average shares outstanding under United States GAAP (in thousands)			
Basic	128,598	115,065	84,547
Diluted	128,598	119,895	84,547

The Company has no items that would be disclosed as other comprehensive income under United States GAAP.

Stock based compensation

The Company has a stock-based compensation plan as more fully described in Note 7. With regards to its stock option plan, the Company applies APB Opinion No. 25, as interpreted by FASB ("FIN") 44, in accounting for this plan and accordingly no compensation cost has been recognized. Had compensation expense been determined based on fair value at the stock option grant date, consistent with the method of Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation, the Company's net loss (income) and net loss (income) per share would have been reduced to the pro forma amounts indicated below:

	Year ended December 31,		
	2001	2000	1999
Net loss (income) under United States GAAP	\$36,264	\$ (5,429)	\$ 7,802
Pro forma (thousands)	\$38,091	\$ (3,289)	\$11,840
Net loss (income) per common share under United States GAAP	\$ 0.28	\$ (0.05)	\$ 0.08
Pro forma	\$ 0.30	\$ (0.03)	\$ 0.12
Stock options issued during period (thousands)	846	1,991	2,065
Weighted average exercise price	\$ 2.99	\$ 4.29	\$ 1.73
Weighted average fair value of options granted during the period	\$ 1.92	\$ 2.32	\$ 1.96
Compensation cost (thousands)	\$ —	\$ —	\$ —

The foregoing information is calculated in accordance with the Black-Scholes option pricing model, using the following data and assumptions: volatility, as of the date of grant, computed using the prior one to three-year weekly average prices of the Company's common shares, which ranged from 59% to 108%; expected dividend yield — 0%; option terms to expiry — 5 to 10 years as defined by the option contracts; risk-free rate of return as of the date of grant — 4.87% to 5.70%, based on five year Government of Canada Bond yields.

Consolidated Balance Sheets

The application of United States GAAP would have the following effects on balance sheet items as reported:

Shareholders' Equity

Shareholders' equity at December 31, 2001 under Canadian GAAP	\$ 96,897
Adjustment to ascribed value of shares issued for royalty interests (Note 3)	1,358
Impairment provision for China properties required under United States GAAP	(10,000)
Write off of GTL development costs required under United States GAAP	<u>(5,142)</u>
Shareholders' equity at December 31, 2001 under United States GAAP	<u>\$83,113</u>
Shareholders' equity at December 31, 2000 under Canadian GAAP	\$95,838
Adjustment to ascribed value of shares issued for royalty interests (Note 3)	1,358
Shareholders' equity at December 31, 2000 under United States GAAP	<u>\$97,196</u>

Under United States GAAP, the transfer of deficit to share capital, which occurred during the year ended December 31, 1999, would not be recognized (Note 5). As a result, shareholders' equity under United States GAAP would comprise the following:

	As at December 31,	
	2001	2000
Share capital (including adjustments above)	\$196,205	\$174,024
Deficit (including adjustments above).....	(113,092)	(76,828)
	<u>\$ 83,113</u>	<u>\$ 97,196</u>

Oil and Gas Properties

There are certain differences between the full cost method of accounting for oil and gas assets as applied in Canada and as applied in the United States. The principal difference results in the method of performing ceiling test evaluations under the full cost accounting rules. Under Canadian GAAP, non-discounted future net revenues from oil and gas production, less an estimate for future general and administrative expenses, financing costs and income taxes are compared to the carrying value of the depletable petroleum properties, whereas for United States GAAP future net revenues are discounted to present value at 10% per annum and compared to the carrying value of the depletable petroleum properties. The Company has performed the ceiling test in accordance with US GAAP and determined that there would be an additional provision for impairment required in connection with the Company's China properties of \$10,000,000. No material variances in financial statement balances would have resulted in 2000 or 1999.

The categories of costs included in the cost of oil and gas properties, equipment and GTL investments, including the adjustments in accordance with U.S. GAAP, to the ascribed value of shares issued for royalty interests of \$1,358,000 (Note 3), an additional provision for impairment of \$10,000,000 and the write off of GTL development costs are as follows:

	As at December 31,		
	2001	2000	1999
Property acquisition costs	\$ 15,956	\$10,268	\$ 3,878
Royalty rights acquired	10,582	6,539	5,217
Exploration costs.....	20,918	9,373	4,865
Development costs.....	45,325	26,414	10,239
GTL license, investment and feasibility studies.....	12,000	13,253	—
Support equipment	468	368	174
	105,249	66,215	24,373
Accumulated depletion and depreciation	(3,437)	(397)	(130)
Provision for impairment	(24,000)	—	—
	<u>\$ 77,812</u>	<u>\$65,818</u>	<u>\$24,243</u>

Accounts payable and accrued liabilities

The following is the breakdown of accounts payable and accrued liabilities:

	As at December 31,	
	2001	2000
Accounts payable.....	\$5,144	\$2,912
Accrued salaries and related expenses	782	—
Accrued interest	10	10
Other accruals	38	29
Total.....	<u>\$5,974</u>	<u>\$2,951</u>

Consolidated Statements of Cash Flow

As a result of the write off of GTL development costs required under United States GAAP the statement of cash flow as reported would change as follows: cash flow from operating activities would change from a cash flow of \$2,433,000 to a cash flow deficiency of \$2,709,000, and oil and gas properties, equipment and GTL investments reported under investing activities of \$40,504,000 would change to \$35,362,000.

Impact of New and Pending United States GAAP Accounting Standards

In June 2001, the Financial Accounting Standards Board ("FASB") approved SFAS No. 141, "Business Combinations" and issued this statement in July 2001. SFAS No. 141 establishes new standards for accounting and reporting requirements for business combinations and will require that the purchase method of accounting be used for all business combinations initiated after June 30, 2001. Use of the pooling of interest method will be prohibited. Management does not believe that SFAS No.141 will have a material impact on the Company's financial statements.

In June 2001, the FASB approved SFAS No. 142 "Goodwill and Other Intangible Assets", which supercedes APB Opinion No. 17, "Intangible Assets". The FASB issued this statement in July 2001. SFAS No.142 establishes new standards for goodwill acquired in a business combination and eliminates amortization of goodwill and instead sets forth methods to periodically evaluate goodwill for impairment. Management does not believe that SFAS No.142 will have a material impact on the Company's financial statements.

In June 2001, the FASB approved SFAS No. 143, "Accounting for Asset Retirement Obligations", which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS No.143 is effective for fiscal years beginning after June 15, 2002.. Management does not believe that SFAS No.143 will have a material impact on the Company's financial statements.

In October 2001 the FASB issued SFAS No.144, "Accounting for the Impairment or Disposal of Long-Lived Assets", resolving significant implementation issues related to FASB Statement No.121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of", and supercedes the accounting and reporting provisions of APB Opinion No.30, "Reporting the Results of Operations- Reporting the Effects of Disposal of a Segment of a Business and Extraordinary, Unusual and Infrequently Occurring Events and Transactions", for the disposal of a business segment. SFAS No.144 is effective for the fiscal years beginning after December 15, 2001 and interim periods within those fiscal years. Management does not believe that SFAS No.144 will have a material impact on the Company's financial statements.

SUPPLEMENTARY DISCLOSURES ABOUT OIL AND GAS PRODUCTION ACTIVITIES (UNAUDITED)

The following information about the Company's oil and gas producing activities is presented in accordance with United States Statement of Financial Accounting Standards No. 69: Disclosures About Oil and Gas Producing Activities.

Oil and Gas Reserves

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic conditions.

Proved developed oil and gas reserves are reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

Estimates of oil and gas reserves are subject to uncertainty and will change as additional information regarding the producing fields and technology becomes available and as future economic conditions change.

Reserves presented in this section represent the Company's working interest share of reserves net of royalties. The reserves for 2001 and 2000 in the U.S. are based on estimates by the independent petroleum engineering firm of Joe C. Neal & Associates and Allan Spivak Engineering. In China, the reserves are based on estimates by the independent petroleum engineering firm of Gilbert Laustsen Jung Associates Ltd.

Our Daqing project in China was sold subsequent to year end. For purposes of the schedules detailed below the total reserves for Daqing of 3,449 MBbls at December 31, 2001 are included and valued at the consideration to be received in 2002.

The Company's net proved and net proved developed oil and gas reserves are as follows:

	Oil (MBbl)	Gas (MMcf)
Net proved reserves, December 31, 1998	8,800	—
Production	(807)	—
Loss of remaining reserves in Russia	(7,993)	—
Acquisition — Sunwing	<u>20,848</u>	—
Net proved reserves, December 31, 1999	20,848	—
Extensions and discoveries	4,803	6,301
Production	(133)	(5)
Revisions to previous estimates	<u>276</u>	—
Net proved reserves, December 31, 2000	25,794	6,296
Extensions and discoveries	923	651
Production	(377)	(127)
Revisions to previous estimates	<u>(2,542)</u>	<u>(5,189)</u>
Net proved reserves, December 31, 2001	<u>23,798</u>	<u>1,631</u>
Net Proved Developed Reserves		
December 31, 1999	—	—
December 31, 2000	1,573	984
December 31, 2001	1,808	1,215

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves

The following standardized measure of discounted future net cash flows from proved oil and gas reserves has been computed using period end prices of \$15.37 per barrel of oil (\$23.95 per barrel in 2000 and \$22.95 per barrel in 1999) and \$2.76 per Mcf of gas (\$5.65 per mcf in 2000) and costs and period end statutory tax rates. A discount rate of 10% has been applied in determining the standardized measure of discounted future net cash flows.

The Company does not believe that this information reflects the fair market value of its oil and gas properties. Actual future net cash flows will differ from the presented estimated future net cash flows in that:

- future production from proved reserves will differ from estimated production;
- future production will also include production from probable and potential reserves;
- future rather than year end prices and costs will apply; and
- existing economic, operating and regulatory conditions are subject to change.

The standardized measure of discounted future net cash flows as at December 31 in each of the three most recently completed financial years are as follows:

	2001	2000	1999
	(in thousands)		
Future cash inflows	\$370,344	\$653,419	\$469,260
Future development and restoration costs	137,581	162,399	130,283
Future production costs.....	156,103	145,130	86,253
Future income taxes.....	<u>5,526</u>	<u>102,831</u>	<u>79,878</u>
Future net cash flows	71,134	243,059	172,846
10% annual discount	<u>52,845</u>	<u>141,823</u>	<u>101,736</u>
Standardized measure	<u>\$ 18,289</u>	<u>\$101,236</u>	<u>\$ 71,110</u>

Changes in standardized measure of discounted future net cash flows as at December 31 in each of the three most recently completed financial years are as follows:

	2001	2000	1999
Sale of oil & gas net of production costs.....	\$ (4,386)	\$ (64)	\$ (1,310)
Revenue credited to China property costs.....	—	(2,940)	(92)
Net changes in pricing and production costs	(110,584)	(3,433)	834
Purchase of reserves	—	—	71,202
Discoveries and extensions	4,955	19,266	—
Abandonment of reserves	—	—	(4,707)
Revisions of previous estimates	22,167	1,707	—
Net change in future development costs	(1,640)	9,611	—
Accretion of discount	6,541	5,979	—
Increase (decrease)	(82,947)	30,126	65,927
Standardized measure, beginning of year	101,236	71,110	5,183
Standardized measure, end of year.....	<u>\$ 18,289</u>	<u>\$101,236</u>	<u>\$71,110</u>

Costs Incurred in Oil and Gas Property Acquisition, Exploration, Development and GTL Activities for the following periods ended:

	Year ended December 31,	
	2001	2000
	(in thousands)	
Property Acquisition		
Proved	\$ —	\$ —
Unproved	5,688	6,392
Royalty rights	4,043	1,321
Development	19,091	16,436
Exploration	11,545	4,508
GTL license and investment	—	13,252
	<u>\$40,367</u>	<u>\$41,909</u>

Depletion, per unit of net production, before provision for impairment:

	\$/boe
United States	
Year ended December 31, 2001	\$8.12
Year ended December 31, 2000	\$8.70
China	
Year ended December 31, 2001	\$6.79
Russia	
Year ended December 31, 1999	\$3.04

Results of Producing Activities:

	Year ended December 31,		
	2001	2000	1999
Petroleum and natural gas revenue	\$ 9,144	\$ 851	\$5,460
Operating costs	4,758	787	4,150
Depletion (including provision for impairment)	27,133	275	1,665
Other.....	—	—	(48)
Loss before income taxes	(22,747)	(211)	(307)
Income tax (recovery)	—	—	—
Results of operations from producing activities	<u>\$ (22,747)</u>	<u>\$ (211)</u>	<u>\$ (307)</u>

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The following table provides the names of all of our directors and executive officers, their positions, terms of office and their principal occupations during the past five years. Each director is elected for a one year term or until his successor has been duly elected or appointed. Officers serve at the pleasure of the Board of Directors.

Name, Age and Municipality of Residence	Position with the Registrant	Present Occupation and Principal Occupation for the Past Five Years
DAVID R. MARTIN, age 70 Santa Barbara, California	Chairman of the Board and Director (since August, 1998)	Chairman of the Board of Ivanhoe Energy Inc. (August 1998 — present); President, Cathedral Mountain Corporation (1997 — present); President and Chief Executive Officer, Occidental Oil & Gas Corporation (1986- 1996); Executive Vice President and Director, Occidental Petroleum Corporation (1986-1996)
ROBERT M. FRIEDLAND, age 51 Hong Kong	Deputy Chairman (since June, 1999) and Director (since February 1995)	Chairman and President, Ivanhoe Capital Corporation
E. LEON DANIEL, age 65 Park City, Utah	President, Chief Executive Officer (since June, 1999) and Director (since August, 1998)	President and Chief Executive Officer of Ivanhoe Energy Inc. (June, 1999 — present); Executive Vice President, Worldwide Business Development, Occidental Oil and Gas Corporation (1996-1998); President, Occidental Engineering Co. (1993-1996); President, Worldwide Exploration, Occidental Petroleum (1997-1998)
JOHN A. CARVER, age 69 Bakersfield, California	Director (since August, 1998)	Retired (1998); Senior Vice President, Worldwide Exploration, Occidental Petroleum (1997-1998); Consultant (1996-1997); Executive Vice President, Worldwide Exploration, Occidental Oil and Gas Corporation (1994-1996)
R. EDWARD FLOOD, age 56 Reno, Nevada	Director (since June, 1999)	Deputy Chairman, Ivanhoe Mines Inc. (May, 1999 — present); Mining Analyst, Haywood Securities (May, 1999 — September 2001) President, Ivanhoe Mines Inc. (1995-1999); Member and Gold Analyst of Contrarian Fund Management Team of Robertson Stephens & Company (1993-1995)
SHUN-ICHI SHIMIZU, age 61 Tokyo, Japan	Director (since July, 1999)	Managing Director of C.U.E. Management Consulting Ltd. (1994 to present)

Name, Age and Municipality of Residence	Position with the Registrant	Present Occupation and Principal Occupation for the Past Five Years
HOWARD R. BALLOCH, age 50 Beijing, China	Director (since January, 2002)	President, White Birch International Ltd. (July 2001 — present); President, Canada China Business Council (July 2001 — present); Canadian Ambassador to China, Mongolia and Democratic Republic of Korea (April 1996 — July 2001); prior thereto, Deputy Secretary for Intergovernmental Relations to the Cabinet of the Government of Canada (April 1994 — March 1996); prior thereto, various positions in the Department of External Affairs, Canada (1976 — April 1994)
JOHN O'KEEFE, age 53 Houston, Texas	Executive Vice-President, Investor Relations and Chief Financial Officer (since September, 2000)	Executive Vice-President, Investor Relations and Chief Financial Officer of Ivanhoe Energy Inc. (September 2000 — present); Vice-President, Investor Relations of Santa Fe Snyder Corporation (1999 — September 2000); Director, Investor Relations of Oryx Energy Company (1991-1999)
PATRICK CHUA, age 46 Hong Kong, China	Executive Vice-President (since June, 1999)	Executive Vice-President of Ivanhoe Energy Inc. (June, 1999 — present); President and Director of Sunwing Energy Ltd. (Bermuda) (March 2000 — present) Co-Chairman and Director of Sunwing Energy Ltd. (June, 1996 — June, 1999); Co-Chairman and director, Sunwing Energy Ltd. (BVI) (May, 1995 — December 2001); prior thereto, Project Manager and Senior Engineer, Sproule Associates Limited
GERALD MOENCH, age 53 Lethbridge, Alberta	Executive Vice-President (since June, 1999)	Executive Vice-President of Ivanhoe Energy Inc. (June, 1999 — present); President and Director, Sunwing Energy Ltd. (July, 1997 — June, 1999); Acting President, Sunwing Energy Ltd. (June, 1996 — July, 1997); Consultant in Indonesia and New Zealand (January, 1995 — June, 1996); prior thereto, General Manager, Santos Petroleum (Seram) Ltd.

Listed below are those of our directors who hold directorships in other publicly listed corporations and the names of those corporations:

ROBERT M. FRIEDLAND:	Ivanhoe Mines Ltd.
R. EDWARD FLOOD:	Diamond Fields International Ltd., Emperor Mines Limited, Ivanhoe Mines Ltd. Olympus Pacific Minerals Inc.
HOWARD R. BALLOCH:	Zi Corporation

Each of our directors, with the exception of Mr. Howard Balloch who was appointed to the Board in January, 2002, was elected at our last annual general meeting of shareholders. The term of office of each director concludes at our next annual general meeting of shareholders, unless the director's office is earlier vacated in accordance with our by-laws. There are no family relationships among any of our directors, officers or key employees.

As required under the *Business Corporations Act (Yukon)*, our Board of Directors has an Audit Committee. We also have a Compensation and Benefits Committee. The members of the Audit Committee are Messrs. Edward Flood, Howard Balloch and Shun-Ichi Shimizu. The members of the Compensation and Benefits Committee are Messrs. David Martin and Edward Flood.

Management is responsible for our financial reporting process including our system of internal control and for the preparation of consolidated financial statements in accordance with generally accepted accounting principles in Canada. Our independent auditors are responsible for auditing those financial statements. The members of the audit committee are not our employees, and are not professional accountants or auditors. The audit committee's primary purpose is to assist the Board of Directors to fulfill its oversight responsibilities by reviewing the financial information provided to shareholders and others, the systems of internal controls which management has established to preserve our assets and the audit process. It is not the audit committee's duty or responsibility to conduct auditing or accounting reviews or procedures or to determine that our financial statements are complete and accurate and in accordance with generally accepted accounting principles in Canada. In giving its recommendation to the Board of Directors, the audit committee has relied on management's representations that the financial statements have been prepared with integrity and objectivity and in conformity with generally accepted accounting principles in Canada and on the representations of the independent auditors included in their report on our financial statements.

Based solely on a review of the reports furnished to us, we believe that during 2001 all of our directors, executive officers and 10% shareholders complied with the applicable requirements for reporting initial ownership and changes in ownership of our common shares.

ITEM 11. EXECUTIVE COMPENSATION

During the fiscal year ended December 31, 2001 we paid our executive officers \$804,955 aggregate cash compensation. In 2001 the Company adopted a defined contribution retirement or thrift plan (401(k) Plan) to assist U.S. employees in providing for retirement or other future financial needs. Employees contributions (up to the maximum allowed by U.S. tax laws) are matched by the Company 50% in 2001 and increasing 10% per year thereafter to a maximum of a 100%.

The following executive compensation disclosure relates to our President and Chief Executive Officer as at December 31, 2001, and each of our four most highly compensated executive officers (collectively, the "named executive officers") whose annual compensation exceeded \$100,000 in the year ended December 31, 2001. During the year ended December 31, 2001, the total compensation paid to those of our officers who received more than \$100,000 in total compensation was \$804,955.

Summary Compensation

We paid the following compensation during the years ending December 31, 1999, 2000 and 2001 to each of our named executive officers.

SUMMARY COMPENSATION TABLE

Name and Principal Position	Year	Annual Compensation			Long Term Compensation			All Other Compensation (\$)
		Salary (\$)	Bonus (\$)	Other Annual Compensation	Awards		Payouts	
					Securities Under Options/SARs Granted (#)	Restricted Shares or Restricted Share Units	LTIP Payouts (\$)	
E. LEON DANIEL President & Chief Executive Officer(1)	2001	150,000						
E. LEON DANIEL President & Chief Executive Officer(1)	2000	200,000	22,000	1,144(6)	500,000			
E. LEON DANIEL President & Chief Executive Officer(1)	1999	148,580						
PATRICK CHUA Executive Vice President(2)	2001	180,000						
PATRICK CHUA Executive Vice President(2)	2000	180,000		4,711(6)				1,530
PATRICK CHUA Executive Vice President(2)	1999	133,722		6,892(6)	500,000			
JOHN O'KEEFE Chief Financial Officer Executive Vice President Investor Relations(3)	2001	174,955			200,000			5,250
JOHN O'KEEFE Chief Financial Officer Executive Vice President Investor Relations(3)	2000	58,333						
JOHN O'KEEFE Chief Financial Officer Executive Vice President Investor Relations(3)	1999							
DAVID MARTIN Chairman(4)	2001	150,000						3,000
DAVID MARTIN Chairman(4)	2000	50,000	110,000					
DAVID MARTIN Chairman(4)	1999							
GERALD MOENCH Executive Vice President(5)	2001	150,000						
GERALD MOENCH Executive Vice President(5)	2000	150,000		3,112(6)				
GERALD MOENCH Executive Vice President(5)	1999	111,435		4,583(6)	200,000			745

- (1) Mr. E. Leon Daniel was appointed as our President and Chief Executive Officer on June 22, 1999, and has been one of our directors since August 25, 1998.
- (2) Mr. Chua was appointed as an Executive Vice-President in June, 1999.
- (3) Mr. O'Keefe has been Executive Vice President Investor Relations and Chief Financial Officer since September, 2000.
- (4) Mr. Martin has been our Chairman and one of our directors since August, 1998.
- (5) Mr. Moench was appointed an Executive Vice-President in June, 1999.
- (6) Includes premiums paid by us on behalf of the named executive officer for medical, dental and other health insurance coverage.

Options and Stock Appreciation Rights (SARS)

We granted the following Options/SARS to our named executive officers in the financial year ended December 31, 2001:

OPTION/SAR GRANTS IN LAST FISCAL YEAR

Name	Number of Securities Underlying Options/SARS Granted (#)	Percent of Total Options/SARS Granted to Employees in Fiscal Year	Exercise of Base Price (\$/Sh)	Expiration Date	Grant Date Present Value \$(1)
JOHN O'KEEFE	250,000	29.57	\$3.60	December 21, 2006	\$3.60

- (1) Equal to or greater than the weighted average price of our common shares on The Toronto Stock Exchange for the five trading days preceding the date of a grant.

Aggregated Option Exercises

The aggregate number of options exercised by any of the named executive officers during the financial year ended December 31, 2001 was 5,000.

AGGREGATED OPTION/SAR EXERCISES IN LAST FISCAL YEAR AND FINANCIAL YEAR END OPTION/SAR VALUES

Name	Shares Acquired on Exercise (#)	Aggregate Value Realized (\$)	Number of Underlying Securities Unexercised Options/SARS at FY-End (#) Exercisable/Unexercisable	Value of Unexercised in the Money Options/SARS at FY-End (Cdn.\$) Exercisable/Unexercisable
GERRY MOENCH	5,000	28,750	115,000 /80,000	128,800 /89,600

Pension Plans

We do not presently provide a pension plan for our employees however, in 2001 the Company adopted a defined contribution retirement or thrift plan (401(k) Plan) to assist US employees in providing for retirement or other future financial needs. Employees contributions (up to the maximum allowed by US tax laws) are matched by the Company 50% in 2001 and increasing 10% per year thereafter to a maximum of 100%. The Company's contributions to the 401(k) Plan in 2001 was \$78,000.

Employment Contracts, Termination of Employment and Change-In-Control Arrangements

We have no written employment contracts or termination of employment or change of control arrangement with any of our directors or named executive officers except for John O'Keefe, whose employment contract provides for one year's severance, without cause, and on termination the immediate vesting of all outstanding options.

Director and Named Executive Officer Compensation

We did not pay cash or other fixed compensation to our directors. Effective January 1, 2002 all independent directors will receive director fees of \$2,000 per month. We reimburse our directors for expenses they reasonably incur in the performance of their duties as directors and they are also eligible to receive stock bonus awards from time to time and to participate in our Employees' and Directors' Equity Incentive Plan.

The cash compensation we pay to the named executive officers is intended to be comparable to the cash compensation paid to executive officers of similar companies who have comparable duties and responsibilities.

Employees' and Directors' Equity Incentive Plan

Our Employees' and Directors' Equity Incentive Plan, as amended (the "Plan") consists of three component plans: a common share option plan (the "Share Option Plan"), a common share bonus plan (the "Share Bonus Plan"), and a common share purchase plan (the "Share Purchase Plan"). The purpose of the Plan is to advance our corporate interests, by encouraging equity participation by our directors, officers, employees and service providers through the acquisition of our shares.

The following is a brief description of the terms of the Plan.

Share Option Plan

The Share Option Plan allows the board of directors to grant options to acquire our common shares in favour of our directors, officers, employees and service providers. Options are subject to adjustment in the event of a subdivision or consolidation of our common shares, an amalgamation, or other corporate event affecting our common shares. Participation in the Share Option Plan is limited to directors, officers, employees and service providers, who are, in the opinion of our board of directors, in a position to contribute to our future growth and success.

In determining the number or value of optioned common shares made subject to options, we consider the optionee's present and potential contribution to our success and to the prevailing policies of each stock exchange on which our shares are listed. The board of directors determines the date of grant, the number of shares, the exercise price per share, the vesting period, and all other terms and conditions of the options we grant. The minimum exercise price of any option granted under the Share Option Plan is the weighted average price of our common shares on the principal stock exchange on which our common shares trade for the five trading days prior to the date of grant.

Unless earlier terminated upon an optionee's death or termination of employment or appointment, options are exercisable for a period of up to ten years. We may, in our discretion, accelerate unvested options if a take-over bid is made for our common shares.

We may also grant share appreciation rights when we grant an option. Such rights permit an optionee to elect to terminate the option and instead receive common shares on the basis of a cashless exercise. The number of common shares that an optionee who exercises share appreciation rights will receive is equal to the difference between the then fair market value per common share and the option price per common share of all common shares under option, divided by the then fair market value per common share.

Share Bonus Plan

The Share Bonus Plan permits our board of directors to issue a maximum of 1,000,000 of our common shares as bonus awards to our directors, employees and service providers on a discretionary basis having regard to such merit criteria as the board of directors may determine.

Share Purchase Plan

Participation in the Share Purchase Plan is limited to employees who have completed at least one year (or less, at the discretion of the board of directors) of continuous service on a full-time basis and who are designated by the board of directors as eligible to participate in the Share Purchase Plan.

Eligible employees may contribute up to 10% of their annual basic salary to the Share Purchase Plan in semi-monthly installments. We then make contributions on a quarterly basis equal to the employee's contribution.

At the end of each calendar quarter, the eligible employee receives a number of our common shares equal to the aggregate amount contributed by the employee participant and by us, on the participant's behalf, divided by the weighted average trading price of our common shares on our principal stock exchange during the previous three months.

The Share Purchase Plan component of the Plan has not yet been activated.

General

The aggregate maximum number of our common shares which we may issue or reserve for issuance under the Plan is currently 15,000,000 common shares. Any increase is subject to Toronto Stock Exchange approval and approval by our shareholders. The maximum number of our common shares which we may, at any time, reserve for issuance to any one person under the Plan may not exceed 5% of our issued and outstanding common shares.

Our board of directors has the right to amend, modify or terminate our Equity Incentive Plan. However, any amendment to the Equity Incentive Plan which would materially increase the benefits under the Plan, materially modify the requirements as to eligibility for participation in the Plan or materially change the number of our common shares that may be issued or reserved for issuance under the Plan, is subject to Toronto Stock Exchange approval and the approval of our shareholders.

Compensation Committee Interlocks and Insider Participation

During the year ended December 31, 2001, our Compensation and Benefits Committee consisted of Messrs. Robert Friedland, Edward Flood and David Martin. Mr. Martin is one of our executive officers. Mr. Friedland is our largest shareholder and holds interests in other entities with which we have transacted, and continue to transact, business. See Item 13. "Certain Relationships and Related Transactions." Mr. Friedland resigned his position on the Compensation and Benefits Committee in the second half of the year ended December 31, 2001.

Board Compensation Committee Report on Executive Compensation

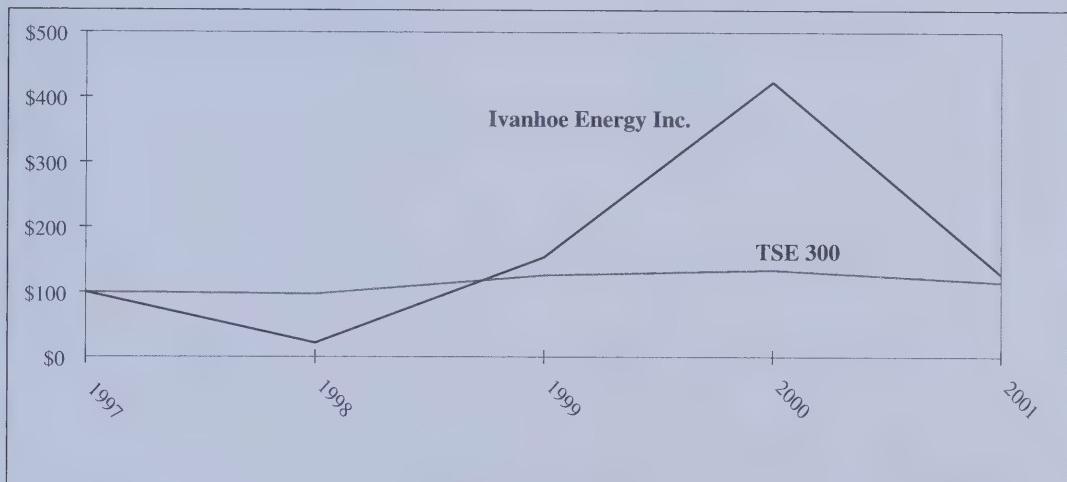
The Compensation and Benefits Committee administers our executive compensation program, which is designed to provide incentives for our executive officers to enhance shareholder value. Our principal objectives are to attract and retain qualified executives critical to our success, to provide fair and competitive compensation, to align their interests with those of our shareholders, and to reward extraordinary corporate and individual performance on an annual basis. We structure each compensation package in a manner that we believe links shareholder return, measured by appreciation in share price, with executive compensation. Stock options are the primary mechanism we use to align management and shareholder interests. We do not offer pension plans to our senior executives.

Submitted on behalf of the Compensation Committee:

Mr. Edward Flood
Mr. David Martin

Performance Graph

The following graph and table compares the cumulative shareholder return on a \$100 investment in common shares of the Company to a similar investment in companies comprising the TSE 300 Total Return Index, including dividend reinvestment, for the period from December 31, 1997 to December 31, 2001.



	Dec. 31, 1997	Dec. 31, 1998	Dec. 31, 1999	Dec. 31, 2000	Dec. 31, 2001
Ivanhoe Energy Inc.	Cdn. \$100	Cdn. \$ 22	Cdn. \$153	Cdn. \$423	Cdn. \$128
TSE 300 Total Return Index	Cdn. \$100	Cdn. \$ 97	Cdn. \$126	Cdn. \$133	Cdn. \$115

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Except as set forth below, no person or group is known to beneficially own (as deemed by SEC Regulations) 5% or more of our issued and outstanding common shares. Based on information known to us, the following table sets forth the beneficial ownership of each such person or group in our common shares at March 1, 2002.

Title of Class	Name and Address of Beneficial Owner	Number of Shares Beneficially Owned(1)	Percentage of Class
Common Shares	Robert M. Friedland(2) Flat B, 31st Floor Primrose Court 56A Conduit Road Mid-Levels, Hong Kong	46,611,725	33.41%
Common Shares	Capital Research and Management Company 333 South Hope Street Los Angeles, California 90071	12,692,200(3)	8.94%
Common Shares	Paul Stephens 388 Market Street Suite 200 San Francisco, California 94111	7,683,600	5.51%
Common Shares	Directors and Executive Officers as a Group (10 persons)	51,560,068(4)	36.17%

- (1) Beneficial ownership is determined in accordance with the rules of the Securities and Exchange Commission and generally includes voting or investment power with respect to securities. Unissued common shares subject to options, warrants or other convertible securities currently exercisable or convertible, or exercisable or convertible within 60 days, are deemed outstanding for the purpose of computing the beneficial ownership of common shares of the person holding such convertible security but are not deemed outstanding for computing the beneficial ownership of common shares of any other person.
- (2) 46,194,620 outstanding common shares are held indirectly through Newstar Securities Ltd., Premier Mines Limited and Evershine LLC, companies controlled by Mr. Friedland.
- (3) Includes 2,500,000 common shares issuable upon exercise of share purchase warrants.
- (4) Includes 3,024,733 common shares issuable upon the exercise of incentive stock options held by directors and executive officers as a group.

Security Ownership of Management

The following table sets forth the beneficial ownership at March 1, 2002 of our common shares by each of our directors, our named executive officers and by all of our directors and executive officers as a group:

<u>Title of Class</u>	<u>Name of Beneficial Owner</u>	<u>Amount and Nature of Beneficial Ownership(1)</u>	<u>Percentage of Class</u>
Common Shares	David Martin	2,997,952	2.12
Common Shares	Robert M. Friedland	46,611,725	33.41
Common Shares	E. Leon Daniel	681,097	0.49
Common Shares	John A. Carver	443,627	0.32
Common Shares	R. Edward Flood	65,029	0.05
Common Shares	Shun-ichi Shimizu	72,500	0.05
Common Shares	John O'Keefe	221,832	0.16
Common Shares	Patrick Chua	366,120	0.26
Common Shares	Gerald Moench	80,186	0.06
Common Shares	Howard Balloch	20,000	0.01
Common Shares	All directors and executive officers as a group (10 persons)	51,560,068	36.17%

(1) Includes unissued common shares issuable upon the exercise of incentive stock options.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Transactions with Management and Others

Not applicable.

Certain Business Relationships

We are parties to cost sharing agreements with other companies in which Mr. Robert M. Friedland has a material direct or indirect beneficial interest. Through these agreements, we share office space, furnishings, equipment and communications facilities in Vancouver, Singapore and London and an aircraft on a cost recovery basis. We also share the costs of employing administrative and non-executive management personnel at these offices. During the year ended December 31, 2001, our share of these costs was \$2,650,000. The companies, with which we are parties to the cost sharing agreements, and Mr. Friedland's ownership interest in each of them, are as follows:

<u>Company Name</u>	<u>Robert Friedland Ownership Interest</u>
Ivanhoe Mines Ltd.	58.78%
Ivanhoe Capital Corporation	100%
African Minerals Ltd.	57.46%
Diamond Fields International Ltd.	7.72%
Pangaea Energy International Ltd.	72%

A company controlled by a director, and a director receive fees for providing consulting services. During the year ended December 31, 2001 a company controlled by Mr. Shun-ichi Shimizu received \$673,000 for consulting services and out of pocket expenses. Mr. John Carver receives \$30,000 per quarter for services provided.

**TABLE OF INDEBTEDNESS OF DIRECTORS, EXECUTIVE OFFICERS
AND SENIOR OFFICERS**

Name and Principal Position	Involvement of Issuer or Subsidiary	Largest Amount Outstanding During 2001	Amount Outstanding as at March 1, 2002
DAVID MARTIN Chairman	Loan Agreement	\$211,438	\$212,315
R. EDWARD FLOOD Director	Loan Agreement	\$ 63,431	\$ 63,695

We loaned Messrs. Martin and Flood Cdn. \$200,000 and Cdn. \$60,000 respectively in January, 2001 to facilitate their exercise of warrants to purchase 50,000 and 15,000 of our common shares respectively. The loans bear interest at the Bank of Montreal prime rate as quoted from time to time and the loans were to mature on January 26, 2002. By a Directors resolution of January 9, 2002 the loans were renewed under the same terms and conditions and now mature on January 26, 2003. The loans are secured by a pledge of the 50,000 common shares owned by Mr. Martin and the 15,000 common shares owned by Mr. Flood.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

The following financial statements and exhibits are filed as part of this Annual Report:

(a) 1. **Financial Statements:**

Deloitte & Touche, LLP Auditors' Report on Consolidated Balance Sheets of Ivanhoe Energy Inc. as at December 31, 2001 and 2000 and Consolidated Statements of Loss and Deficit and Consolidated Statements of Cash Flow of Ivanhoe Energy Inc. for the years ended December 31, 2001, 2000 and 1999.

Consolidated Balance Sheets of Ivanhoe Energy Inc. as at December 31, 2001 and 2000.

Consolidated Statements of Loss and Deficit of Ivanhoe Energy Inc. for the years ended December 31, 2001, 2000 and 1999.

Consolidated Statements of Cash Flow of Ivanhoe Energy Inc. for the years ended December 31, 2001, 2000 and 1999.

Notes to the Consolidated Financial Statements of Ivanhoe Energy Inc. for the years ended December 31, 2001, 2000 and 1999.

2. **Financial Statement Schedules:**

Supplementary Disclosures about Oil and Gas Production Activities (Unaudited)

3. **Exhibits**

- 3.1 Articles of Ivanhoe Energy Inc. as amended to June 24, 1999 (incorporated by reference to Exhibits 1.1 through to 1.4 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).
- 3.2 Bylaws of Ivanhoe Energy Inc. (incorporated by reference to Exhibit 1.1 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).
- 4.1 Amended and Restated Convertible Loan Agreement dated August 4, 1999 between Ivanhoe Energy Inc. and Linyi Holdings Ltd. (incorporated by reference to Exhibit 3.2 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).
- 10.1 Funding and Participation Agreement dated August 1, 1998 between Ivanhoe Energy (USA) Inc. (formerly West Best Resources Ltd.) and Diatom Petroleum, Incorporated (incorporated by reference to Exhibit 3.3 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).
- 10.2 Exploration Agreement dated May 1, 1998 between Diatom Petroleum, Incorporated and Aera Energy LLC, as amended January 18, 1999, March 29, 1999, September 15, 1999, September 21, 1999 and April 5, 2000 (incorporated by reference to Exhibit 3.4 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).
- 10.3 Participation Agreement dated August 1, 1996 between Aera Energy LLC (formerly CalResources, LLC), Digital Petrophysics, Inc., Ivanhoe Energy (USA) Inc. (formerly West Best Resources Ltd.) (as assignee of Texaco Exploration and Production Inc.) and Wood Oil Company, as amended December 11, 1998 and further amended October 13, 1999 (incorporated by reference to Exhibit 3.5 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).

- 10.4 Participation Agreement dated February 15, 1999 between Aera Energy LLC, Ivanhoe Energy (USA) Inc. (formerly West Best Resources Ltd.), Diatom Petroleum, Inc. and Armstrong Resources, LLC, as amended September 9, 1999 and further amended November 15, 1999 (incorporated by reference to Exhibit 3.9 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).
- 10.5 Petroleum Contract for Kongnan Block, Dagang Oilfield of the People's Republic of China dated September 8, 1997 between China National Petroleum Corporation and Pan-China Resources Ltd., as amended June 11, 1999 (incorporated by reference to Exhibit 3.15 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).
- 10.6 Exploration Agreement dated October 1, 1999 between Prime Natural Resources, LLC, Ivanhoe Energy (USA) Inc. and Aera Energy LLC (incorporated by reference to Exhibit 3.23 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).
- 10.7 Service Agreement dated September 1, 1999 of CUE Management Consultants Limited (incorporated by reference to Exhibit 3.31 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).
- 10.8 Volume License Agreement dated April 26, 2000 between Syntroleum Corporation and Ivanhoe Energy Inc. (incorporated by reference to Exhibit 3.37 of Amendment No. 2 to Form 20-F filed with the Securities and Exchange Commission on July 24, 2000).
- 10.9 Agreement dated May 11, 2000 between Discovery Operating, Inc., Don L. Sparks and Ivanhoe Energy (USA) Inc. (incorporated by reference to Exhibit 3.38 of Amendment No. 2 to Form 20-F filed with the Securities and Exchange Commission on July 24, 2000).
- 10.10 Consultancy Agreement dated June 2, 2000 between Ivanhoe Energy Inc. and M&A Oil Consultancy Limited (incorporated by reference to Exhibit 3.39 of Amendment No. 2 to Form 20-F filed with the Securities and Exchange Commission on July 24, 2000).
- 10.11 Master License Agreement Amendment No. 1 dated October 11, 2000 between Syntroleum Corporation and Ivanhoe Energy Inc. (incorporated by reference to Exhibit 10.18 of Form 10-K filed with the Securities and Exchange Commission on March 16, 2001).
- 10.12 Consulting Agreement dated November 15, 2000 between Ivanhoe Energy Inc. and Continental Energy Limited (incorporated by reference to Exhibit 10.19 of Form 10-K filed with the Securities and Exchange Commission on March 16, 2001).
- 10.13 Employees' and Directors' Equity Incentive Plan (incorporated by reference to Exhibit 10.20 of Form 10-K filed with the Securities and Exchange Commission on March 16, 2001).
- 10.14 Agreement for the Sale and Purchase of Shares in Great Plains Petroleum (Cyprus) Limited and Global Petroleum (Cyprus) Limited dated August 10, 2000 between Kuban Petroleum Ltd., Ivanhoe Energy Inc. and Stesana Enterprises Limited (incorporated by reference to Exhibit 10.21 of Form 10-K filed with the Securities and Exchange Commission on March 16, 2001).
- 10.15 Deed of Release dated August 10, 2000 between Ivanhoe Energy Inc., Kuban Petroleum Ltd., Tyumen Oil Company and Tyumeneftegaz (incorporated by reference to Exhibit 10.22 of Form 10-K filed with the Securities and Exchange Commission on March 16, 2001).
- 10.16 Agreement to Purchase shares of Digital Petrophysics, Inc. dated January 26, 2001 between Ivanhoe Energy (USA) Inc., William R. Berry II and Deborah M. Olsen (incorporated by reference to Exhibit 10.23 of Form 10-K filed with the Securities and Exchange Commission on March 16, 2001).

- 10.17 Memorandum of Understanding dated February 13, 2001 between PetroChina Company Limited and Sunwing Energy Ltd. to conduct a Joint Feasibility Study of Zitongxi and Zitongdong Blocks (incorporated by reference to Exhibit 10.24 of Form 10-K filed with the Securities and Exchange Commission on March 16, 2001).
- 10.18 Memorandum of Understanding dated February 13, 2001 between PetroChina Company Limited and Sunwing Energy Ltd. to conduct a Joint Feasibility Study of Yudong Block (incorporated by reference to Exhibit 10.25 of Form 10-K filed with the Securities and Exchange Commission on March 16, 2001).
- 10.19 Agreement and Operating Agreement dated 5 March 2001 between Discovery Operating, Inc., Don L. Sparks, W. Jeffrey Sparks, Kevin D. Sparks, C. Todd Sparks and Ivanhoe Energy (USA) Inc. with respect to oil and gas interests in Midland and Upton County, Texas.
- 10.20 Participation Agreement dated 10 March 2001 between Hay Exploration, Inc. and Ivanhoe Energy (USA) Inc. with respect to oil and gas properties in Elliott, Morgan and Carter Counties, Kentucky.
- 10.21 Joint Study Agreement between Petro China Company Limited and Sunwing Energy Ltd. dated 29 March 2001, for the purposes of entering into Production Sharing Contracts on the Yudong block.
- 10.22 Joint Study Agreement between Petro China Company Limited and Sunwing Energy Ltd. dated 29 March 2001, for the purposes of entering into Production Sharing Contracts on the Zitongxi and Zitondong blocks.
- 10.23 Joint Venture Agreement and Operating Agreement dated 1 July 2001 between Union Oil Company of California and Ivanhoe Energy (USA) Inc. on the Cresslen Ranch Area, Henderson County, Texas.
- 10.24 Joint Venture Agreement and Operating Agreement dated 1 October 2001 between Union Oil Company of California and Ivanhoe Energy (USA) Inc., in the Bossier Trend, Anderson, Freestone & Henderson Counties, Texas.
- 10.25 Modification Agreement for Petroleum Development Contract for Kongnan Block, Dagang Oilfield, the People's Republic of China, dated 24 October 2001.
- 10.26 Amendment of Petroleum Contract for Petroleum Development and Production in Zhou 13 Block, Daqing Zhaozhou Oilfield, of the People's Republic of China dated 28 December 2001.
- 10.27 Consulting Agreement dated 13 January 2002 between Ivanhoe Energy Inc. and Nahwan Trading LLC.
 - 21.1 Subsidiaries of Ivanhoe Energy Inc.
 - 23.1 Consent of Gilbert Laustsen Jung Associates Ltd., Petroleum Engineers.
 - 23.2 Consent of Allan Spivak Engineering.
 - 23.3 Consent of Joe C. Neal & Associates.

(b) Reports on Form 8-K:

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

IVANHOE ENERGY INC.

By: /s/ E. LEON DANIEL

Name: E. Leon Daniel

Title: President and Chief Executive Officer

Dated: March 14, 2002

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>/s/ E. LEON DANIEL</u> E. Leon Daniel	President, Chief Executive Officer and Director (Principal Executive Officer)	March 14, 2002
<u>/s/ JOHN O'KEEFE</u> John O'Keefe	Executive Vice-President and Chief Financial Officer (Principal Financial and Accounting Officer)	March 14, 2002
<u>/s/ DAVID MARTIN</u> David Martin	Chairman of the Board and Director	March 14, 2002
<u>/s/ ROBERT M. FRIEDLAND</u> Robert M. Friedland	Deputy Chairman and Director	March 14, 2002
<u>/s/ JOHN A. CARVER</u> John A. Carver	Director	March 14, 2002
<u>/s/ R. EDWARD FLOOD</u> R. Edward Flood	Director	March 14, 2002
<u>/s/ SHUN-ICHI SHIMIZU</u> Shun-ichi Shimizu	Director	March 14, 2002
<u>/s/ HOWARD BALLOCH</u> Howard Balloch	Director	March 14, 2002

OFFICE LOCATIONS**Corporate**

Suite 654-999 Canada Place
Vancouver, BC
Canada V6C 3E1
604 688 7166
604 682 2060 FAX

Operations

1200 Discovery Drive, Suite 301
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81 3 3258 3222
81 3 3258 3850 FAX

China

Suite # 1900, 101-6th Avenue SW
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403 274 7853 FAX

OFFICERS

Leon Daniel
John O'Keefe
Pat Chua
Gerry Moench
Beverly Bartlett

President and Chief Executive Officer
Executive Vice President and Chief Financial Officer
Executive Vice President
Executive Vice President
Corporate Secretary

BOARD OF DIRECTORS

David Martin (1)
Robert Friedland
Leon Daniel
Howard Balloch (2)
John Carver
Edward Flood (1) (2)
Shun-ichi Shimizu (2)

Chairman
Deputy Chairman
President and Chief Executive Officer

(1) - Member of Compensation Committee

(2) - Member of Audit Committee

REGISTRAR AND TRANSFER AGENT

CIBC Mellon Trust Company
Vancouver, Canada
604 688 4330

INVESTOR INFORMATION

Web site: www.ivanhoeenergy.com
E-mail: info@ivanhoeenergy.com

Houston

281 565 7486
281 565 7485 FAX

Bakersfield

661 869 2887
661 869 2820

Vancouver

604 688 8323
604 688 7168

MARKET LISTINGS

Toronto Stock Exchange: **IE**

Nasdaq National Market: **IVAN**



IVANHOE
ENERGY

www.ivanhoe-energy.com

NASDAQ: IVAN TSE: IE